Estimated energy costs for 2013-14 retail tariffs

Estimated energy costs by retail tariff for use by the Queensland Competition Authority in its Draft Determination on retail electricity tariffs for 2013-14

Prepared for the Queensland Competition Authority

February 2013

ACIL Tasman

Economics Policy Strategy

ACIL Tasman Pty Ltd

ABN 68 102 652 148
Internet www.aciltasman.com.au

Melbourne (Head Office)
Level 4, 114 William Street
Melbourne VIC 3000

Telephone (+61 3) 9604 4400
Facsimile (+61 3) 9604 4455
Email melbourne@aciltasman.com.au

Brisbane
Level 15, 127 Creek Street
Brisbane QLD 4000
GPO Box 32
Brisbane QLD 4001

Telephone (+61 7) 3009 8700
Facsimile (+61 7) 3009 8799
Email brisbane@aciltasman.com.au

Canberra
Level 2, 33 Ainslie Place
Canberra City ACT 2600
GPO Box 1322
Canberra ACT 2601

Telephone (+61 2) 6103 8200
Facsimile (+61 2) 6103 8233
Email canberra@aciltasman.com.au

Perth
Centa Building C2, 118 Railway Street
West Perth WA 6005

Telephone (+61 8) 9449 9600
Facsimile (+61 8) 9322 3955
Email perth@aciltasman.com.au

Sydney
Level 20, Tower 2 Darling Park
201 Sussex Street
Sydney NSW 2000
GPO Box 4670
Sydney NSW 2001

Telephone (+61 2) 9389 7842
Facsimile (+61 2) 8080 8142
Email sydney@aciltasman.com.au

For information on this report

Please contact:

Marcus Randell
Telephone 07 3009 8700
Mobile 0404 822 319
Email m.randell@aciltasman.com.au

Contributing team members

Paul Hyslop
Richard Lenton
Cara Chambers
Martin Pavelka

Contents

List of charts

List of figures

List of tables

1 Introduction

This report provides estimates of expected energy costs for use by the Queensland Competition Authority (the Authority) in developing retail electricity tariffs for 2013-14.

The report also considers the submissions made by various parties following the Authority's Consultation Paper, *Regulated Retail Electricity Prices 2013-14: Cost Components and Other Issues* (December 2012) where those submissions refer to the cost of energy in regulated retail electricity prices.

Retail prices generically consist of three components:

- network costs
- energy costs
- costs associated with retailing to end users.

This report is concerned with the energy costs component only. In accordance with the Ministerial Delegation (the Delegation) which is attached as Appendix A and the Consultancy Terms of Reference (TOR) provided by the Authority and which is attached as Appendix B, the methodology developed by ACIL Tasman provides an estimate of energy costs to be incurred by a retailer to supply customers on notified prices for 2013-14; i.e. non-market customers. Energy costs comprise wholesale energy costs, other energy costs associated with renewable energy incentives, market fees and ancillary services charges and transmission and distribution losses.

1.1 Background

In accordance with the Delegation and the TOR, ACIL Tasman notes that its task is to provide expert advice to the Authority on the energy costs to be incurred by a retailer to supply customers on notified prices for 2013-14. In preparing its advice we are required to have regard to the actual costs of making, producing or supplying the goods or services which in this case are the customer retail services to be supplied to non-market customers for the tariff year 1 July 2013 to 30 June 2014. In establishing the most appropriate methodology for undertaking this task, we have considered a range of approaches which might be used to estimate the wholesale energy cost component.

In the interest of clarity, in undertaking the task, ACIL Tasman has not been tasked to provide expert advice on:

- the effect that the price determination might have on competition in the Queensland retail market

- the Queensland Government uniform tariff policy
- time of use pricing
- any transitional arrangements that might be considered or required.

ACIL Tasman understands that these matters will be considered by the Authority when making its Determination.

In determining the question as to what constitutes the actual cost of making, producing or supplying customer retail services to customers supplied on notified prices, ACIL Tasman has taken a consistent approach with advice it provided to the Authority for the 2012-13 Determination, which was tested in the Supreme Court of Queensland and found to meet the requirements of the Act and Delegation.

1.2 Methodology

ACIL Tasman’s methodology is consistent with the methodology that was used to provide advice to the Authority for the 2012-13 Determination. Some refinements have been made to the methodology which is in part in response to matters that have been raised by stakeholders. Some other refinements have been made as part of ACIL Tasman’s ongoing development of the underlying methodology and modelling capability.

The approach adopted by ACIL Tasman is designed to simulate the wholesale energy market from a retailing perspective, where retailers hedge the pool price risk by entering into electricity contracts with prices represented by the observable futures market data. Other energy costs are added to the wholesale energy costs and the total is then adjusted for assumed network losses.

1.2.1 Pool modelling/price distribution

The pool price modelling involves developing hourly pool prices and load profiles for 462 simulations of 2013-14, using ACIL Tasman's electricity market simulator, *PowerMark*. These are used in conjunction with the retailer contracting model to estimate wholesale energy costs (WEC).

1.2.2 Electricity Hedging

The retailer contracting model simplifies of the actual contract market in that it is based on observable prices for base, peak and cap contracts only. These building block contracts are used to develop a standardised contract strategy which is then used in conjunction with the 462 simulations of 2013-14 to estimate the WEC.

1.2.3 Other energy costs

Other costs are largely based on a building block approach as follows:

- Renewable Energy costs are based on legislated targets for the large-scale renewable energy target (LRET) and the most recently published data for the small-scale renewable energy scheme (SRES).
- Queensland Gas Scheme
- National Electricity Market (NEM) management fees
- Ancillary services
- Prudential costs.

2 Response to the submissions

This section responds to a variety of comments and proposals made in submissions by stakeholders in response to the Authority's Consultation Paper, *Regulated Retail Electricity Prices 2013-14: Cost Components and Other Issues* (December 2012)

2.1 Consideration of LRMC/PPA/generation costs

A number of submissions proposed various changes to the methodology to incorporate the long run marginal cost (LRMC) of generation, to take account of prices paid for long dated power purchase agreements (PPA) or to incorporate costs incurred in owning generation assets.

ACIL Tasman does not agree with these proposals, as in our opinion they are less likely than the market based approach to produce reasonable estimates for wholesale energy costs for retailers supplying non-market customers with electricity retail services in 2013-14 in Queensland.

The market based approach reflects the gross pool nature of the NEM and the fact that all retailers must purchase electricity through the pool in 2013-14, which they may then choose to hedge. In this sense observable hedging costs for the year in question and credible estimates of expected pool prices would be expected to provide a realistic estimate of the actual costs that retailers face in supplying electricity retail services to the non-market customer segment.

The alternative proposals are considered in more detail in turn below.

2.1.1 LRMC

ACIL Tasman has considered the issue of using LRMC previously. LRMC is a long run concept in that it refers to a time horizon over which all factors of production may be varied. While LRMC is calculated at a point in time, the horizon for the calculation is usually over many years, potentially as long as 25 to 40 years, being the typical investment horizon for energy market assets.

Hence, LRMC, even if calculated using the so called 'greenfield' approach is unlikely to be reflective of the actual costs faced by a retailer in supplying non-market customers in Queensland with electricity retail services in 2013-14, except as a matter of coincidence.

2.1.2 PPA

ACIL Tasman has also previously considered the use of PPA in determining wholesale energy costs. PPA are usually long dated instruments linked to the construction or possibly the mid-life refinancing of generation assets. They usually represent an average price reflecting the value of the PPA over its full life. This as a matter of course may include some years when the PPA price is lower than the current market price and some years when it is above the current market price.

As PPA have often been executed quite some time ago in the past, they may not reflect the long term market value over the life of the PPA; i.e. they may have been written in a period when investors were more optimistic or pessimistic about the future and so may include a favourable or unfavourable bias in their pricing.

As the PPA price may be above or below the market in any particular year, or where the pricing is biased as a consequence of being committed in a more optimistic or pessimistic period, may be above or below the market in every year (or nearly every year), the use of PPA to estimate wholesale energy costs is unlikely to be reflective of the actual costs faced by a retailer in supplying non-market customers in Queensland with electricity retail services in 2013-14.

2.1.3 Generation costs

ACIL Tasman has also previously considered the use of actual generation costs. Using actual generation costs is very similar to using long dated PPA and essentially suffers the same flaws. In particular, the use of actual generation costs as has been proposed, would seek to use average generation costs and potentially incorporate generation costs which may never be fully recovered through the market, especially where the expected business case for investing in the generation does not eventuate. Notably the actual costs as proposed by some parties assume a required capital return. In the competitive environment of the NEM, no generation investor can expect to be guaranteed a 'required' capital return on investment.

For very similar reasons to LRMC and PPA, the use of actual generation costs to estimate wholesale energy costs is unlikely to be reflective of the actual costs faced by a retailer in supplying non-market customers in Queensland with electricity retail services in 2013-14.

2.2 Futures contracts representing hedging costs

A number of submissions noted that that not all electricity contracts are traded through the futures market and if they were, that substantially higher price outcomes are likely to eventuate because of the increased demand.

ACIL Tasman does not agree with this contention. If more contracts were purchased through the futures market, then this implies existing supply that is meeting that demand currently through bilateral[1] or over-the-counter (OTC)[2] trading would move to provide supply through the futures market. The increased supply would be executed to offset the increased demand and all other things being equal, price would be expected to largely be the same.

The core issue in using the futures market as a representation of electricity contract prices for the year in which the estimates are to be made is considering whether the futures market has enough depth and liquidity to allow participants to capture any arbitrage across the futures market and bilateral /OTC contract markets. If so prices in each contract market should reflect prices in the other contract markets.

ACIL Tasman notes that liquidity is an issue in all of the electricity contract markets. However, based on the volumes traded in the futures market for the year in question, we are satisfied that sufficient liquidity exists to promote efficient arbitrage should prices move significantly out of kilter in each of the contract markets.

2.3 Potential changes in contract prices post Final Determination

Origin Energy in its supplementary submission note that the adopted hedging methodology assumes that *retailers have completed all hedging for the coming financial year by the preceding May* (assuming the final contract prices used in the Determination are updated in May 2013). And that the *extent to which a retailer does not follow this theoretical hedging strategy in structure or timing* results *in material risks which are not accommodated in the proposed tariff*. Origin use the example of the price spikes in the Queensland region of the NEM in January 2013 resulting in a 25 per cent increase in base futures price for Q1 2013.

Unfortunately, Origin does not provide an indication of what proportion of a retailer's quarterly load is typically exposed just prior to the start of the given quarter. One would expect a reasonable proportion of load to be hedged just prior to the commencement of the quarter. If for example, 90 per cent of the load is already covered at the commencement of the quarter then the recent 25 per cent increase in contract prices for Q1 2013 would equate to a 2.5 per cent increase in hedge costs across the whole of the retailer's quarterly load. If the remaining three quarters do not experience the same level of change in contract price then the 2.5 per cent increase for Q1 then equates to a 0.625 per cent increase across the year.

[1] Between individual parties and may be bespoke in nature.

[2] Normally relatively standard products traded through brokers.

Given the quick response of the futures market to any changes in the spot market within a given quarter, being significantly exposed just prior to the commencement of the given quarter is unlikely to be viewed as a prudent risk strategy since it effectively means the retailer is exposed to the spot market.

2.4 Scaling of demands

AGL expressed concern that the approach used to derive the NSLP load traces *does not adequately reflect the additional volatility in the NSLP compared with the Queensland system load*.

An expanded explanation of the methodology used to derive the NSLP demand traces is provided in Section 3.2.1 to assist stakeholders in better understanding the ACIL Tasman approach.

AGL expressed concerns that the variability in annual peak demand across the 42 simulated demand sets for the NSLP is underrepresented as a result of the methodology. AGL provided the data in Table 1 below in order to demonstrate that in their view, the variation in NSLP annual peak demand as measured by the peak demand for 2009-10 (2,785MW) over the average of annual peak demands for the period 2007-08 to 2011-12 (2,650MW) is about nine per cent.

ACIL Tasman does not agree that this is a valid measure of variation since the state of the economy and underlying structure of the NSLP load is different for each year. Figure 1 shows the load duration curve[3] for the Energex NSLP for the years 2009-10 to 2011-12. It can be seen that in general terms the volume of the NSLP has been decreasing over the past three years - partly as a result of customers exiting the NSLP and the increased penetration of rooftop solar PV. It is reasonable to expect that the top 10 per cent or so of demands are affected by temperature, and temperature patterns may be different from one year to the next. However, given the remainder (90 per cent) of the load duration curve in 2011-12 is about 200MW or so less than in 2009-10 then it is likely that the peak demand in 2009-10 would have been about 200MW lower had the underlying economy in Queensland and solar PV penetration levels of 2011-12 been present in 2009-10. This being the case, the variation as measured by AGL reduces from nine per cent to less than one per cent.

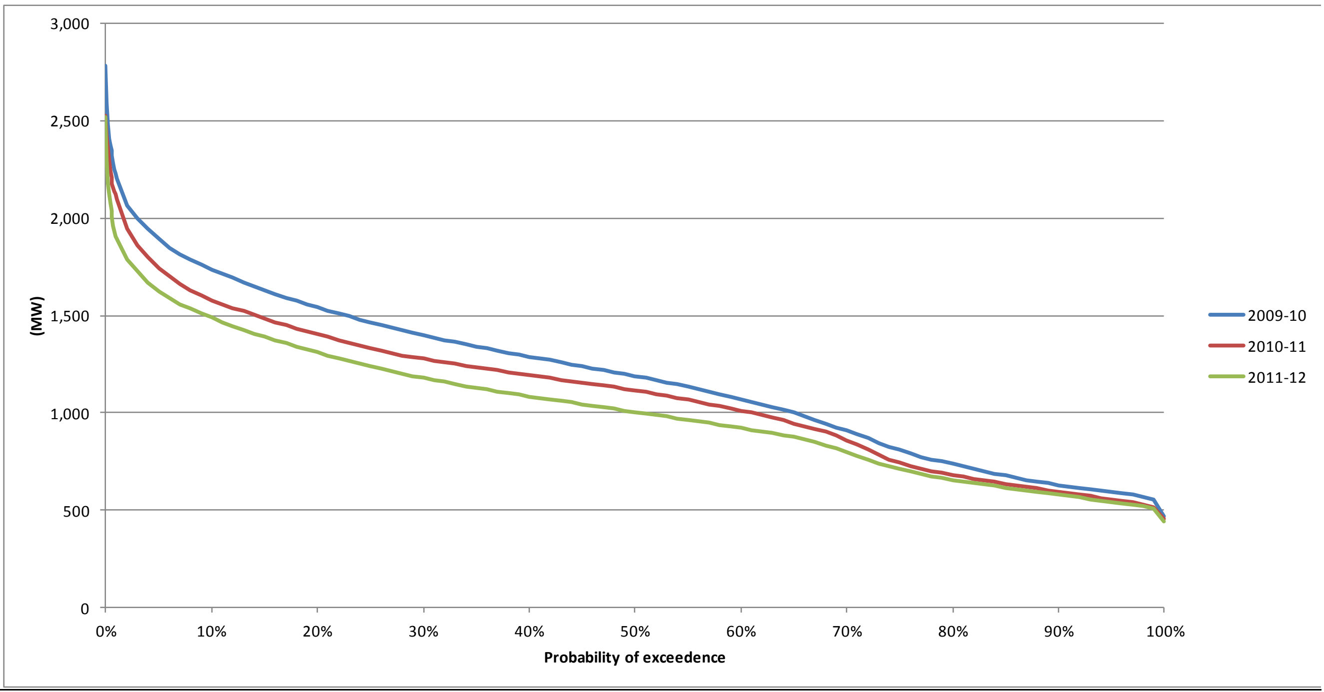
[3] A load duration curve is a plot of the half hourly demands after being sorted from highest to lowest.

Table 1 **Historical maximum demand (MW) for Queensland and Energex NSLP**

Financial Year	Maximum Qld system	Maximum Energex NSLP
2007-08	8,116	2,386
2008-09	8,683	2,582
2009-10	8,931	2,785
2010-11	8,846	2,528
2011-12	8,714	2,521

Data source: AGL submission and ACIL Tasman analysis of AEMO data

Figure 1 **Energex NSLP half-hourly load duration curves - 2008-10 to 2011-12**



Data source: ACIL Tasman analysis of AEMO data

Further, it is important to note that the half-hourly Queensland demand and the half-hourly NSLP demand is not perfectly correlated - averaging around 0.91 over the past few years (across all 17,520 half hours in the year). If the correlation calculation is constrained to the peak periods, which are typically the periods of interest in terms of price volatility and risk, then it decreases to less than 0.7. Therefore, comparing the historical variation in the peak demands of the NSLP with the historical variation in the peak demands in Queensland at such a high level can lead to false conclusions about the relationship between the two sets of demands.

The table below shows that the annual peak demands for Queensland and the Energex NSLP have not occurred at the same time. This is an observation worth considering - at the time that the Energex NSLP peaks, and potentially the time at which retailers are most exposed in relation to the Energex NSLP, the Queensland demand is between 400MW and 1,000MW less than its annual peak. In other words, there is no certainty that prices will reach their highest levels at the time of the peak NSLP demand.

Table 2 **Coincidence of historical maximum demand (MW) for Queensland and Energex NSLP**

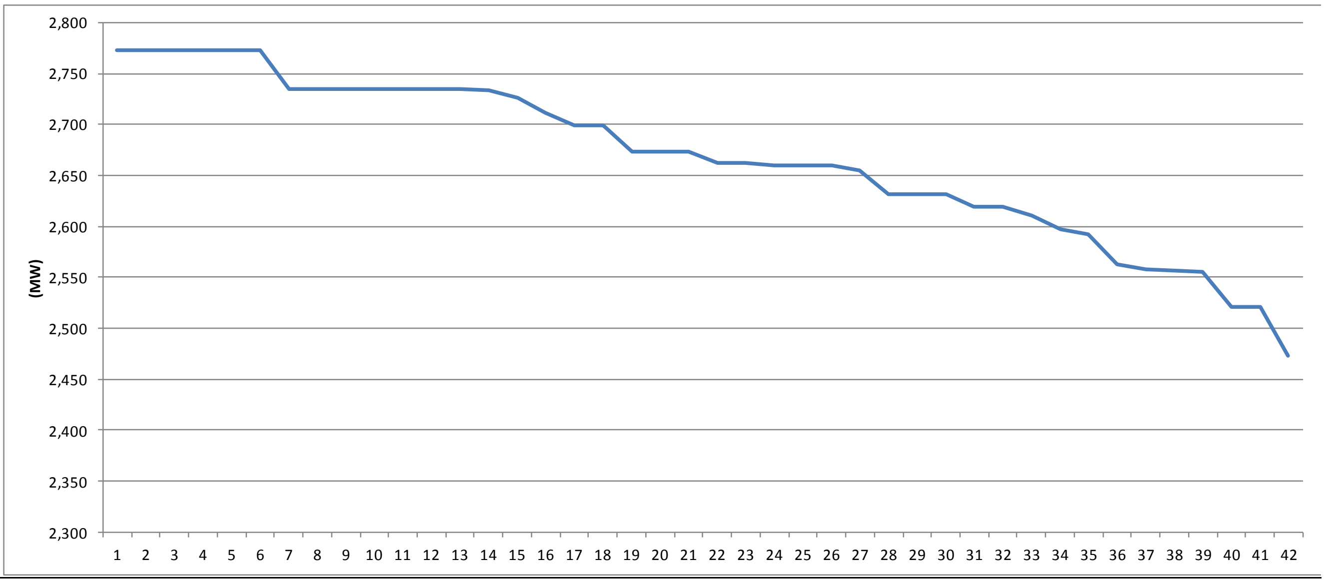
Financial Year	Maximum Qld system	Energex NSLP at time of Qld system peak	Maximum Energex NSLP	Qld system demand at time of Energex NSLP peak
2009-10	8,931	2,603	2,785	8,590
2010-11	8,846	2.459	2,528	7,845
2011-12	8,714	2,354	2,521	8,227

Data source: AGL submission and ACIL Tasman analysis of AEMO data

Using the ACIL Tasman methodology, the variation between the maximum peak demand and the median peak demand of the 42 simulated load traces for 2013-14 is about four per cent for the Energex NSLP, compared with a variation of about 1.9 per cent for the Queensland load. ACIL Tasman is of the opinion that this appears reasonable given that the recent historical data presented by AGL has not been adjusted for changes in the underlying economy and solar PV penetration.

Figure 2 below shows the projected annual peak demand for each of the 42 simulated demand sets for the 2013-14 Energex NSLP resulting from the application of the methodology described in Section 3.2.1 . The 42 peak demands have a spread of about 300MW. The spread of the forecast 90% probability of exceedence (POE) and 10% POE Australian Energy Market Operator (AEMO) National Electricity Forecasting Report (NEFR) peak demands for Queensland for 2013-14 is about 570MW. In other words, the spread in the projected NSLP peak demands is in excess of 50 per cent of the spread in the forecast Queensland peak demand - which appears reasonable given the historical data.

Figure 2 **Annual peak demand for the Energex NSLP for 42 simulated demand sets - 2013-14**



Data source: ACIL Tasman analysis of AEMO and BOM data

The average annual load factor of the Energex NSLP in recent years is about 42 per cent. The average annual load factor of the simulated Energex NSLP load profiles for 2013-14 is also about 42 per cent. This also provides an indication that the shape of the simulated demand sets has not been compromised by the ACIL Tasman methodology.

2.5 Using actual demands of 2009-10 to 2011-12 to simulate the 42 demand sets

AGL express concern that limiting the demand simulation methodology to the actual demands of 2009-10 to 2011-12 (to simulate the 39 demand sets for 1970-71 to 2008-09) is of

> … importance because there are historical days (between 1970-71 and 2008-09) where the temperature is greater than the maximum temperatures from 2009-10 to 2011-12.

AGL ask the following two questions:

- Is there any mechanism in ACIL's methodology to differentiate historical days with hotter or milder weather?
- If not, does this reduce the range of the historical weather variability?

There is no mechanism in the methodology to differentiate between historical days with temperatures that are hotter than the temperatures in 2009-10 to 2011-12. However, the methodology is not just concerned about matching temperatures in Queensland, it also takes into account the temperatures profiles for each region of the NEM simultaneously. Further, the relationship between daily temperature profile and the daily demand profile is not perfect - which is part of the reason why ACIL Tasman has developed the matching methodology.

The matching methodology will result in the maximum demand from the 42 simulated demands sets being capped at the maximum demand observed between 2009-10 and 2011-12 prior to scaling. However, the demands are then scaled to the AEMO NEFR demand forecast parameters - including the 10%POE, 50%POE and 90%POE peak demand parameters. This results in roughly 10 per cent of annual peak demands in the 42 simulated demand sets having a peak demand equal to the NEFR 10%POE peak demand parameter. Thus the range in annual peak demands in the 42 simulated demands sets, post scaling, are equal the range on the NEFR peak demand parameters.

AGL also note that the *flooding that occurred in 2011 around Brisbane also resulted in reduction of electricity consumption*. ACIL Tasman agrees with this observation and when undertaking the matching process excluded the demands for a period of one week after the floods and for one week after cyclone Yasi. However, the actual demands for this period was included in the demand set for 2010-11 - in essence assuming that once in 42 years there will be an event that reduces demand for a week or two (we note that two major Brisbane floods occurred over this time frame).

Stanwell Corporation express concern that *deriving the load forecast by drawing on the previous three years* will not provide an appropriate shape - *specifically in relation to the more recent impact of solar PV installations and associated load shape change*s. ACIL Tasman agrees with this observation. The methodology makes use of the reports referred to by Stanwell - namely the 2012 AEMO NEFR and the AEMO Rooftop PV Information Paper.

The methodology adds back to the Queensland demand profile an allowance for the estimated output of rooftop solar PV panels for each year in the period 2009-10 to 2011-12. These adjusted demands are used in the matching process to produce the 42 simulated demand sets and then the estimate of output from rooftop solar PV for 2013-14 (based on the AEMO NEFR) is then deducted from each of the 42 simulated demand sets.

2.6 Inclusion of the 2008-09 demand/temperature year

Origin suggest including data from 2008-09 as part of the ACIL Tasman methodology for simulating the 42 sets of half-hourly demands because *this year contains a number of months in which the maximum demand was the highest of recent years*.

Although 2008-09 may contain peak demands which were higher than observed over the past three years, for the reasons outlined in Section 2.4, ACIL Tasman does not think it is necessarily valid to reach the conclusion that including 2008-09 data will improve the establishment of the correlation between temperature and demand.

2.7 Transmission constraints

Origin Energy, as part of its supplementary submission, raised the matter of recent spot price volatility in the Queensland region of the NEM - particularly for January 2013. Prices in January 2013 have averaged around $150/MWh to date, compared with about $56/MWh for the period July 2012 to December 2012.

Origin suggest that the higher prices in January 2013 are

> largely the result of constraints on intra-regional transmission line (855 Calvale-Stanwell and 871 Calvale-Wurdong).

Origin also state that

> there are many conditions which can lead to price volatility, not just organic demand growth and that transmission constraints are a significant driver of pool price volatility in Queensland.

Any model is, by definition, a simplification of the real word - whether it be heuristic, deterministic or statistical. ACIL Tasman considered the potential impact of inter-regional transmission constraints on market outcomes when developing *PowerMark*. However, there is a balance to be struck between over specifying the model and model accuracy. ACIL Tasman regularly tests the accuracy of *PowerMark* by undertaking back casting exercises and continues to be satisfied that the model is fit for purpose.

The transmission constraints referred to by Origin will be alleviated when PowerLink completes construction of the Calvale to Stanwell 275kV line augmentation in 2013 (according to information in the December 2012 newsletter from PowerLink[4]). It is worth noting, to date in January 2013, the following units have been off-line:

- two 350MW units of Tarong
- the 443MW Tarong North
- three 260MW units at Gladstone.

[4] http://www.powerlink.com.au/Projects/Central/Documents/Calvale_Stanwell/Community_Update_-_December_2012.aspx

This represents a total 1,573MW of capacity, and is higher if the recent decommissioning of Collinsville is taken into account. This amount of plant off-line is in ACIL Tasman's opinion, a significant contributing factor to the recent price outcomes, along with the transmission constraints.

2.8 Generator bidding behaviour

Stanwell Corporation considers the

> pool price modelling should reflect actual bidding behaviour rather than based on underlying costs, and that, plant controlled by vertically integrated (VI) entities are typically bid in such a manner to manage overall portfolio positions including load requirements.

ACIL Tasman modelling of the NEM is routinely informed by analysing the actual bidding behaviour of market participants and by back casting exercises which are undertaken on a regular basis to test the validity of *PowerMark's* mechanisms as well as the underlying assumptions.

PowerMark dynamically alters the shape of the offer curve (or bid) for each generator unit by allowing each portfolio of generators to attempt to profit maximise within each market period modelled. An assumed cost (consisting of fuel, carbon and variable O&M costs) is necessary to allow the model's algorithm to attempt to profit maximise. Where appropriate, the cost assumed may be altered to account for other factors, such as temporary excess gas in the short term. Similarly, if a generator is observed bidding below its cost (such as a VI generator) and if the conclusion can be reached that this is likely to be a fundamental feature of the generator's behaviour into the future then its cost assumption is altered in the modelling to reflect this.

2.9 Correlation between projected price volatility and demand

2.9.1 Spot prices

Origin, AGL, QEnergy and EnergyAustralia expressed concern that the methodology would result in an inappropriate correlation between the Queensland demand and NSLP and therefore inappropriate correlation between the NSLP and projected spot price outcomes.

The table below shows that historically, the load weighted spot price for the NSLP averages around a 20% premium (or a multiple of 1.20) over the Queensland time weighted price. This seems reasonable, given that the shape of the NSLP is such that its demands will tend to be higher during times of higher price events. However, care needs to be taken when considering these values since the premium varies from year to year as a consequence of differing demand/supply balance conditions in the market as well as the change in correlation between the NSLP and Queensland demand.

Table 3 includes the projected time weighted prices for Queensland and load weighted prices for the Energex NSLP for 2013-14 based on the ACIL Tasman methodology for both the median simulation and the 95th percentile simulation of the low growth case. The median simulation gives a multiple of 1.14 and the 95th percentile simulation gives a multiple of 1.25. These indicate that the ACIL Tasman methodology is delivering reasonable results when compared with the historical multiples and keeping in mind that the 2013-14 estimates include a price on carbon which is expected to suppress the multiple to some extent (given that the price of carbon is expected to be passed through more in the off-peak periods than in the peak periods) as well as a continued increase in penetration of rooftop solar PV (which tends to soften demand during the peak of the day in summer).

Table 3 **Historical and projected wholesale spot prices ($/MWh, nominal) for Queensland and Energex NSLP**

Financial Year	Qld time weighted price	Energex NSLP load weighted price	Multiple
2008-09	$34.00	$39.92	1.17
2009-10	$33.30	$42.81	1.29
2010-11	$30.97	$38.85	1.25
2011-12	$29.07	$31.31	1.08
2013-14 - median	$55.76	$63.53	1.14
2013-14 - 95th percentile	$65.06	$81.00	1.25

Note: Projected prices based on 462 simulations of the low energy growth scenario
Data source: ACIL Tasman analysis of AEMO data for 2008-09 to 2011-12 and ACIL Tasman analysis for 2013-14

2.9.2 Hedged price outcomes

QEnergy have concerns that the premium for a load following contract to cover the NSLP load and the price for a flat/base contract is not representative of that which they have paid for such a contract(ACIL Tasman notes that the actual premium faced by QEnergy was provided as part of a confidential submission and is not disclosed here).

ACIL Tasman notes that as a load following contract by definition has no residual pool risk, it may be expected to have a higher price than the expected price of a strategy with residual pool risk. Otherwise the seller of the load following contract is taking on additional risk for no expected benefit. ACIL Tasman also notes that buyers may pay large premiums for load following contracts, because while they are attractive to retailers, they are potentially very costly to sellers in terms of capacity to sell other hedge products.

When applying the ACIL Tasman hedging strategy and then comparing the hedged price for the NSLP to the flat price from D-Cypha the multiple is about 1.21 for the 95th percentile simulation (which is the point on the distribution that we propose to use for estimating the energy costs). In our view this falls within the range of plausible outcomes and is consistent with the spot price multiples discussed in section 2.9.1 above which was 1.25 for the 95th percentile unhedged estimate. The dampening to 1.21 is also reasonable in this context as the hedging strategy would be expected to reduce pool price exposure to a greater extent on higher demand days which are typically correlated with higher prices.

Table 4 **Historical and projected hedged wholesale prices ($/MWh, nominal) for Queensland and Energex NSLP**

	Qld flat	Energex NSLP	Multiple
2013-14 - median	$56.89	$66.46	1.17
2013-14 - 95th percentile	$56.89	$68.59	1.21

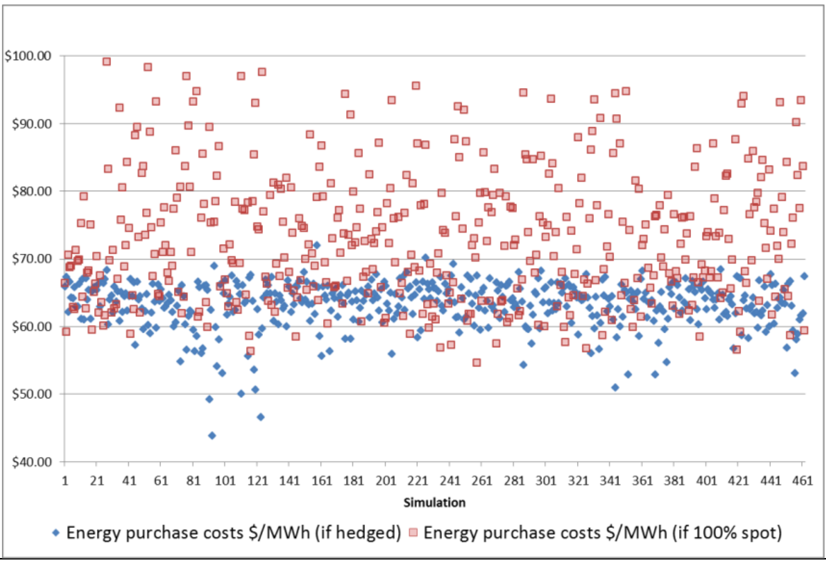
Note: Projected NSLP prices based on 462 simulations of the low energy growth scenario

Data source: ACIL Tasman analysis of D-Cypha data for flat hedge price and ACIL Tasman analysis for 2013-14 NSLP price

2.10 Lack of volatility in estimated hedged outcomes

AGL has expressed concern that there is very little variability in the 462 hedged prices as shown in the graph below which was presented at the December 2012 workshop. Further AGL note that the 462 hedged prices seem to be limited to less than $70 and reach the conclusion that this lack of variability can only be reached if the retailer was fully hedged against all incidences of high prices.

Figure 3 **Annual average price ($/MWh, nominal) for Energex NSLP for 2013-14 - 462 simulations - medium demand growth case (Preliminary Report)**



Data source: ACIL Tasman preliminary analysis

AGL also note that the contract strategy hedges to five per cent above the 50% POE peak demand but suggest given the actual variation is higher at around nine per cent then

> …one would expect significant occurrences where demands exceed the 5% buffer in contract position and in such a case the retailer would be exposed to any high spot prices that occur.

ACIL Tasman's analysis in Section 2.4 highlights that the historical variability in peak demand is less than nine per cent when properly accounting for underlying changes in the economy and rooftop solar PV penetration. The estimated variation for the Energex NSLP in 2013-14 is around four per cent. Therefore, the contracting strategy largely covers the variation in expected maximum peak demand.

Even if we accepted that the variation was nine per cent as estimated by AGL, then only four per cent (or less) of the annual peak demand would be exposed - the other 96 per cent or so would be hedged and not subject to the spike in spot price which is only likely to occur for a handful of occasions each year. For example, if the four per cent of the annual peak demand was exposed and the spot price rose to the current market price cap of $12,900 for this particular half hour then the increase in cost (due to the exposure) is $516/MWh for that half hour (=0.04*$12,900) which would add $0.03/MWh to the annual average cost ($516 divided into the 17,520 half hours in the year). Even if this were to occur for 20 half hours in the year, it would only add $0.60/MWh to the annual average price. In other words, the risk associated with exposure to 4 per cent of the annual peak load for a few hours a year in which it may occur appears very small.

2.11 95th percentile – allowance for risk

Stanwell Corporation expressed concern in relation to using a higher percentile other than the median for estimating the wholesale energy cost component and that ACIL Tasman has not justified the change in methodology. Similarly, QCOSS noted any change in methodology needs to be explained and justified.

The purpose of using the 95th percentile is to properly account for the short term volatility in NEM price outcomes. As noted in the supplementary submission made by Origin, price spikes occur with little or no notice and with little or no time with which to respond.

ACIL Tasman notes that there is some residual pool price risk associated with the hedge portfolio used in estimating wholesale energy costs. In ACIL Tasman's opinion, using the 95th percentile allows for the residual risk associated with a one in 20 year outcome[5] to be incorporated into the wholesale energy cost estimate.

Stanwell *considers there to be equal risk that the modelling fails to appropriately capture drivers that would result in lower market costs*. It may be the case that there is equal risk in understating drivers that contribute to higher or lower price outcomes - but importantly the distribution of price outcomes is not symmetric and is instead skewed towards higher prices. It is the asymmetry in price outcomes, regardless of the symmetry in the drives, which represents the risk to retailers.

Alinta Energy proposes an additional risk allowance to cover unforeseen extreme load or price events. And QEnergy supports the use of the 95th percentile.

Origin in its supplementary submission propose adopting the 99th percentile *recognising the materiality of events in the tail of the distribution*. ACIL Tasman notes that this would represent a 1 in 100 year outcome which in our opinion is not consistent with how most retailers would seek to competitively price risk. ACIL Tasman notes that there is a reasonable degree of price difference between the 95th and 99th percentile if the retailer's load was unhedged and the retailer instead relied 100 per cent on spot market purchases. However, as shown in section 3 of the Report, the hedging strategy substantially reduces the spread in the distribution of outcomes so that the price differential between the 95th and 99th percentile is about 0.5 per cent.

5 A one in 20 year risk management framework is in ACIL Tasman's opinion consistent with how most retailers would assess and seek to manage risk.

2.12 Carbon price uncertainty

AGL raised concerns about accounting for carbon price uncertainty in early d-Cypha trades.

The key dates for carbon pricing are the date on which it was announced (10 July 2011) and the date that the legislation was enacting (8 November 2011).

There were very few trades in Q3 2013 base contracts (41MW), Q4 2013 base contracts (61MW), Q3 2013 peak contracts (5MW) and Q4 2013 peak contracts (5MW) prior to 8 November 2011, the date on which the carbon tax legislation was passed. There were no trades of Q1 2014 and Q2 2014 contracts prior to 8 November 2011.

In relation to the trades that occurred prior to 8 November 2011, they all occurred after the Prime Minister's announcement on 10 July 2011.

Even if some uncertainty was applied to the period between 10 July and 8 November 2011, the few trades in Q3 2013 and Q4 2013 contracts that occurred prior to 8 November 2011, make little impact on the trade-weighted contract price as shown in Table 5 and Table 6 for base and peak contracts respectively.

Table 5 **Impact of trades prior to 8 November 2011 on the trade-weighted price for Q3 2013 and Q4 2013 base contracts**

	Q3 2013		Q4 2013	
	Trade-weighted price	Trade volume MW	Trade-weighted price	Trade volume MW
Base including trades prior to 8 Nov 2011	$53.53	3,999	$54.97	3,829
Base excluding trades prior to 8 Nov 2011	$53.59	3,958	$55.01	3,768
Impact of including trades prior to 8 Nov 2011	-$0.05	41	-$0.04	61

Data source: Analysis based on d-cypha Trade

Table 6 **Impact of trades prior to 8 November 2011 on the trade-weighted price for Q3 2013 and Q4 2013 peak contracts**

	Q3 2013		Q4 2013	
	Trade-weighted price	Trade volume MW	Trade-weighted price	Trade volume MW
Peak including trades prior to 8 Nov 2011	$60.12	75	$64.90	85
Peak excluding trades prior to 8 Nov 2011	$59.88	70	$64.27	80
Impact of including trades prior to 8 Nov 2011	$0.24	5	$0.63	5

Data source: Analysis based on d-cypha Trade

2.13 Liquidity risk premium

AGL consider that the prices used in the hedging component of the methodology should reflect a liquidity risk premium as volumes are often thinly traded and buyers may have to cross bid/ask spreads to transact. The futures prices used to estimate wholesale energy costs are the Daily Settlement Price (DSP) which is set by the futures exchange according to a prescribed set of rules. We understand the rules to set the DSP using the following hierarchy:

- DSP will not be generated at levels less competitive than outright orders at market close
- DSP will be generated from last traded price (including strip leg prices) where more competitive than orders at market close
- If last traded price is outside closing bid / ask spread DSP will be the extreme of the bid / ask spread closest to the last traded price
- Strip leg prices (excluding off-peak strip prices) traded at levels less than the minimum tick increment will be rounded to the closest full tick for settlement purposes.
- Off Peak Strip leg prices will not be used for DSP purposes
- In absence of trades or valid orders DSP will be prior settlement price
- On Listing Date the DSP will be equal to the DSP of the nearest same calendar month contract
- Block Trade prices will not be used for DSP determination.[6]

ACIL Tasman notes that the futures price methodology is volume weighted and hence only reflects days on which contracts traded. This means that the DSP will be either the settlement price or the extreme price of the bid/ask

[6] Daily Settlement Price Determination Process, retrieved from http://d-cyphatrade.com.au/trading/settlement_rules_2 on 29 January 2013

spread closest to the last traded price where the last traded price sits outside the closing bid/ask spread. In ACIL Tasman's view this process accounts for costs associated with crossing the spread as a consequence of limited liquidity.

2.14 Allowance for time risk

QEnergy raised the issue of making an allowance for time risk reflecting the fact that retailers hedge over time. ACIL Tasman notes that time risk is a concept associated with options pricing where the value of the option is generally higher for longer periods to expiry as in effect the longer dated option has a higher probability of being in-the-money. ACIL Tasman agrees, that all other things being equal, hedging further in advance of the period being hedged would generally include a time risk premium compared with hedging closer to the time period being hedged.

ACIL Tasman, in providing advice for the previous Determination, considered a premium for time risk when it was considering estimating energy costs using a pool modelling/price distribution only approach. This approach included estimates of premiums over expected pool prices for hedging. As it turned out, the pool modelling/price distribution approach was not used in our final advice for the previous years Determination, nor has it been proposed or used in our advice for the 2013-14 Determination.

The methodology used in our advice for the 2013/14 Determination relies on a specified hedging portfolio interacting with a distribution of modelled pool price simulations. As hedging is incorporated, by definition time risk is already accounted for in the methodology.

2.15 Allowance for losses

The QCOSS Energy Consumer Advocacy Project through their consultant Etrog have sought further information on the methodology for determining loss factors to be used in the estimates of energy costs. ACIL Tasman has used the available published combined transmission and distribution loss factors for the appropriate tariff classes. For the Draft Determination these involve some prior year loss factors. We expect the 2013-14 estimates to be available for the final Determination.

2.16 Prudential cost allowance

QEnergy has proposed that a number of costs associated with providing prudential obligations are not included in the retail operating cost and should be accounted for separately.

Specifically QEnergy proposed that a number of NEM prudential requirements impose costs on retailers that do not form part of the benchmark retail operating cost. These include

1. \$0.75/MWh to cover the cost of purchasing reallocation certificates to manage prudential obligations to AEMO
2. \$0.33/MWh to cover the cost of providing residual prudential to AEMO (not covered by the reallocation certificates) and
3. \$0.83/MWh to cover the cost of providing prudentials to hedge providers

ACIL Tasman acknowledges that the cost of providing prudentials to AEMO and hedge providers are real costs faced by retail businesses in supplying electricity to regulated customers. QEnergy assesses the funding costs of bank guarantees by using the weighted average cost of capital (WACC) approved by the Australian Energy Regulator for the 2010-2015 Distribution Determination for Energex and Ergon Energy and then adding an additional charge of 2.5%. ACIL Tasman notes that the proposed WACC is a nominal pre-tax WACC and is a reasonable, if not slightly conservative benchmark to use for the purpose of assessing retailer funding costs. The 2.5% additional charge is also reasonable although probably could be considered on the high side.

However, we have some concerns about parts of the approach/methodology applied by QEnergy in proposing the above charges as follows:

- Where bank guarantees are used the cost of a bank guarantee would reflect the additional charge only as the underlying funding cost would only be applicable if the bank guarantee was to be drawn down
- Where cash is used to provide prudential obligations only the funding cost would be applicable
- The cost of reallocation certificates would be expected to reflect the credit status of the buyer as the seller is effectively trading AEMO sponsored pool credit risk for the buyer of the certificates credit risk and hence the stated cost of reallocation certificates is not easily verifiable
- The method of assessing the cost of hedge prudentials differs across counterparties depending on the credit status of both sellers and buyers and can not be considered to be a standard methodology that is used by the industry (ACIL Tasman understands that many counterparties provide some credit limits for trading without any prudential obligations).

ACIL Tasman agrees that it is reasonable to consider that the costs of meeting prudential obligations to AEMO and to hedging providers are specific to the purchasing of energy and managing energy price risk and that these should be accounted for separately. However, ACIL Tasman does not agree with QEnergy's specific estimates of costs. We have assessed the proposed AEMO and hedge prudential costs by comparing them to observable market data. Our estimated costs are set out in section 4.5 of the Report.

2.17 Queensland Gas Scheme

The QCOSS Energy Consumer Advocacy Project commented on the period over which GEC costs are averaged: *The length of time over which they are averaged should be the same as the length of time over which the purchasing of contracts occurs for hedging of wholesale energy costs.*

ACIL Tasman continues to use a period of four years because there is no volume data available for GEC trades. ACIL Tasman understands from anecdotal evidence that trade volumes for GECs have fallen significantly in the past two years or so and therefore extending the period of time to estimate the costs of GECs is in our view appropriate.

2.18 LGC prices

QEnergy's submission states that

> QEnergy does not support the unaltered use of market contract data to estimate the costs of LRECs, because the issues associated with using market data for 'black' energy costs also apply to environmental markets. If the Authority chooses to use observable market contract data as the basis for pricing LRECs, then a premium for price volatility should be applied as per wholesale market energy costs, which can be estimated using historical data on contract price volatility over an annual term.

ACIL Tasman does not accept this position and notes that the methodology treats the LRET futures in the same manner as wholesale electricity futures - no premium is added to the wholesale electricity futures prices. LRET and wholesale electricity futures are both likely to have a premium over expected spot prices incorporated into the traded prices reflecting varying views on risk and uncertainty from both buyers and sellers.

2.19 STC costs

2.19.1 STP estimate

EnergyAustralia suggests

> that the difficulties in estimating SRES costs for any particular tariff year should be dealt with via either of the following approaches:
>
> - a catch up mechanism in the following tariff year to address any over or under-recoveries of SRES costs; or
> - using the STP for the calendar year for the whole of the next tariff year rather than using a combination of the STP binding estimate for the first six months of the tariff year (i.e. July to December) and the non-binding estimate for the next calendar year (January to June)

Similarly, Ergon Energy suggests

> …the challenge with using non-binding estimates for the Small-scale Technology Percentage (STP) targets is that the estimates are often lower than the final binding STP targets upon which final compliance costs are based. Consequently, the compliance costs for retailers can be underestimated.
>
> Ergon Energy agrees with the QCA's approach of using the most current available STP target in the pricing determination, but also suggests that a catch-up mechanism should be introduced to account for any material over or under estimation of the target based on a later change in the STP"

QEnergy also states:

> Given the history of significant under forecasting of STPs for the second half of the Authority's Determination period, QEnergy suggests applying an uplift to the non-binding STP in place at the time. Given no make good has been made on this element of either of the last two years' STP forecasts, it appears reasonable to apply last year's under forecast of 136% to the current target of 7.69%, giving an allocation of 18.15%.

ACIL Tasman acknowledges the non-binding estimate of the STP will not match the final binding STP. Nevertheless, estimating the size of the error in the estimation of the non-binding STP is impractical. Sizable historic revisions have been driven by changes in feed-in tariff arrangements and early termination of solar multipliers pulling forward demand. The current policy settings with reformed feed-in-tariffs and no solar multipliers are likely to be much more stable.

Furthermore, there is little indication that a preceding year's STP estimate provides an indication for any future year's STP determinations. ACIL Tasman is of the view that a non-binding STP by the Clean Energy Regulator provides the best available estimate for future binding STPs.

The concept of a make good adjustment for previous years is not appropriate in the estimate of energy costs as the estimate must be made in relation to the single year of 2013-14. A make good concept also has little merit in a market that is subject to competitive forces.

2.19.2 Prices

ACIL Tasman notes that most submissions agree with the use of the $40 as set by the Clearing House. In contrast the QCOSS Energy consumer advocacy project suggests the methodology

> should take into account the fact that an active market for STCs has developed outside the clearing house, and the current market price for STCs is well below the official $40 price. An efficient representative retailer should be expected to be taking advantage of that market and not paying $40 to purchase its STCs.

ACIL Tasman acknowledges there is an active market for STCs. However, historic prices might not be the best indicator of future prices as the market is designed to clear every year - so in theory prices could be $40 or at least very close to it. This assumes that the Clean Energy Regulator provides an accurate forecast of created certificates underpinning the STP for the next year.

3 Estimation of Wholesale energy cost

This section of the report sets out our estimates for the WEC.

3.1 Outline of approach

The approach adopted by ACIL Tasman is designed to simulate the wholesale energy market from a retailing perspective, where retailers hedge the pool price risk by entering into electricity contracts with prices represented by the observable futures market data. It involves passing hourly pool prices and load profiles for 462 simulations of 2013-14, estimated using ACIL Tasman's electricity market simulator, *PowerMark,* through a retailer contracting model to estimate wholesale energy costs.

The approach is a simplification of the actual contract market in that it is based on specified hedging strategy using observable prices for base, peak and cap contracts only. It does not include other instruments available to retailers, as ACIL Tasman does not have sufficient independently verified information on any such instruments to incorporate them into the energy cost estimates. However, as retailers could avail themselves of the simplified hedging strategy, it is reasonable to assume more sophisticated strategies would result in costs being no higher with an expectation that they should be lower.

3.2 Detailed approach

3.2.1 Developing 42 simulations of load traces each representing 2012/13

The data used in the analysis is in the public domain and is as follows:

- 42 years of three hourly capital city temperature data from 1970-71 to 2011-12
- NEM regional demand traces for three years from 2009-10 to 2011-12[7]
- Energex and Ergon NSLP demand traces for three years from 2009-10 to 2011-12
- 10%, 50% and 90% POE demand and annual energy forecast parameters from the AEMO 2012 NEFR

[7] There are a number of reasons for limiting the analysis to the 2009-10 to 2011-12 time series. First, the process used to develop the 42 simulated load sets, described below, also develops, simultaneously, 42 corresponding wind farm output traces for a number of wind zones in the NEM. There are insufficient wind farm data to populate the wind traces for all wind zones by using data prior to 2009-10. Second, NSLP data prior to 2009-10 only partly complete.

- forecast of installed solar PV capacity for each NEM region for 2013-14 from the AEMO 2012 NEFR
- estimates of installed solar PV capacity for each NEM region for the years 2009-10 to 2011-12 from AEMO 2012 NEFR.

The first step in the process is to extract the actual load traces for three years 2009-10 to 2011-12 from the AEMO published data and include the NEM regional totals, the NSLP and controlled loads in the Energex area and the NSLP in the Ergon area.

The Energex NSLP is used to estimate the wholesale energy costs for <100MWh customers for Queensland and unmetered load in the Energex area. The Ergon Energy NLSP is used to estimate the wholesale energy costs applying to unmetered load and >100MWh customers in the Ergon Energy area.

The extracted NEM regional demands are then adjusted by adding back to the half hourly demand values an estimate of the rooftop solar PV output. The estimated rooftop output is based on data provided by AEMO in the 2012 NEFR as well as an estimate of the typical hourly output profile of the aggregated installations. This step is important since the rapid uptake of rooftop solar PV has changed the demand profile. This step is not applied to the settlement class traces (i.e. the Energex NSLP and controlled tariffs and the Ergon Energy NSLP) since there is insufficient information on the extent of rooftop solar PV penetrating by class (however, this is dealt with further below).

The NEM and settlement class demands for 2009-10 and 2010-11 are scaled so that in broad terms they are at a comparable level to the 2011-12 demands. This is done by assessing the change in underlying energy between 2009-10 and 2011-12 for periods unaffected by weather variations.

At the completion of this step there are three years worth of demand data at 2011-12 levels for each NEM region and settlement class. These demands are then used to populate 42 simulated demand sets each representing 2011-12 based on different weather (temperature) outcomes.

39 simulated load traces (using weather data for 1970-71 to 2008-09) are developed for each NEM region and settlement class. For each day of the 39 weather data sets a set of daily loads (from 2009-10 to 2011-12) is adopted by finding the best matching daily temperature profile (given the season and day type) across the NEM. Matching the temperature is achieved by finding the closest least squares match between the temperature profile for that day and the temperature profile for a day in the three years 2009-10 to 2011-12 across all NEM regions simultaneously. Once the day with the same day type and

season in the three years from 2009-10 to 2011-12 that best matches the temperature profile of the day in question is identified, then all the associated NEM regional and settlement class load traces for that day are selected for the day in question. Data is chosen on a daily basis in this way because we wish to preserve the relationship between the NEM regional loads traces and settlement class load traces.

The 39 simulated demand sets together with the actual demand sets for 2009-10 to 2011-12 give a total of 42 load traces representing 2011-12.

The 42 sets of NEM regional load traces are then scaled to match the 2013-14 demand and energy forecasts from the NEFR (which have been adjusted by adding back on the contribution of rooftop solar PV). The scaling process is applied simultaneously across the 42 simulated load traces so that the total energy of the aggregate 42 simulated load traces is equal to 42 times the forecast annual energy in each NEM region. The maximum of the annual peak demands from the 42 simulated load traces is scaled to match the 10% POE summer demand forecasts in each region. Similarly, the median of the annual peak demands from the 42 simulated load traces is scaled to the 50% POE summer demand forecasts in each region. And, the minimum of the annual peak demands from the 42 simulated load traces is scaled to the 90% POE summer demand forecasts in each region.

The hot weather experienced early in December 2012 resulted in a Queensland demand of 8,453MW which is well below the AEMO 50% POE medium growth forecast of 9,007MW which suggests that the medium growth forecast has a lower probability of being actually achieved. For this reason, ACIL Tasman has adopted the energy and peak demand parameters from the low economic growth scenario in the NEFR which tend to be about 100MW less than the medium growth scenario.

The 42 demand sets for the regional NEM demands are then adjusted by subtracting an assumed solar PV output profile which is derived by adopting the assumed growth in rooftop solar PV installations provided in the NEFR.

There are a number of additional steps used to establish the 42 simulated demand sets for the NSLPs which, because of the need to consider the effects of solar photovoltaic (PV) on demand, have been introduced for the 2013-14 analysis. Unlike the NEM regions, the Energex and Ergon NSLPs do not have an official demand or solar PV forecast.

The following steps describe the process developed by ACIL Tasman to establish the 42 simulations of these NSLPs representing 2013-14:

Step 1. Classify each half hour by month by working or non working day and by peak or off peak. This means that each half hour is classified as one of 48 period types (12 x 2 x 2).

Step 2. Calculate the average half hour demand for each of the 42 simulated years for 2011-12 for both Queensland NEM demand (with the contribution of solar PV deducted) and the NSLPs for each of the 48 period types.

Step 3. For each half hour in the 42 simulations for 2011-12 calculate the differences between the simulated value and the corresponding average value (from Step 2) for Queensland and the NSLPs .

Step 4. For each of the 42 simulations for the year 2011-12, in each half hourly interval calculate the difference that each of the NSLPs difference is (from Step 3) as a percentage of the Queensland difference (from Step 3).

Step 5. For each half hourly interval and for each of the 42 simulations, calculate the difference between the Queensland demand for 2011-12 and Queensland for 2013-14 (with the assumed 2013-14 solar PV contribution deducted for the Queensland demands).

Step 6. For each half hourly interval and for each of the 42 simulations, for each of the NSLPs apply the percentage (from Step 4) to the difference (from Step 5). This is an estimate of the NSLP contribution to variations in the Queensland load.

Step 7. For each half hourly interval and for each of the 42 simulations, add the results (from Step 6) to each of the NSLPs for 2011-12 to give the 42 simulated load traces representing NSLPs in 2013-14.

This process is designed to allow estimation of the 42 simulated years representing 2013-14 for the Energex and Ergon NSLPs based on the NSLPs contribution to variations in the Queensland load. It avoids the need to produce individual forecasts of load or solar PV for the two NSLPs.

3.2.2 Developing 11 plant outage sets for the NEM

PowerMark requires as an input the availability of each generator unit for each half-hour of the year.

Using binomial probability theory ACIL Tasman has simulated 11 sets of forced outages which are defined by an outage rate assumption as well as an outage duration assumption.

This process allows a range of outage outcomes to be produced. The most important factor in outages is coincidence – if a number of units are forced out at the same time, volatile prices usually result. The process used to simulate the outage sets allows these sorts of coincidences to be represented appropriately.

3.2.3 Running *PowerMark* using the 42 demand sets and 11 outage sets

PowerMark is then run to estimate the hourly pool prices for 2013-14 for 462 simulations by using the 42 demand sets and 11 outage sets developed using the steps described above.

The model is then run a second time but with the carbon tax removed so as to provide cost estimates excluding a price on carbon.

Fuel price and other plant cost and other assumptions used in the *PowerMark* modelling are those developed by ACIL Tasman over the past 15 years and are consistent with ACIL Tasman's latest internal Base Case. These assumptions come from a wide variety of sources and are constantly being monitored and updated.

3.2.4 Determine hedging strategy and volumes

For each settlement class, an appropriate hedging strategy which a prudent retailer would be expected to use for each settlement class is estimated by setting the parameters to calculate the base, peak and cap contract volumes based on the median demand/price year. ACIL Tasman has used the same strategy as employed for 2012-13. It was shown to remove almost all the price volatility and produced hedged prices which were very stable regardless of the weather and outage conditions.

Contract volumes are calculated by applying the hedging strategy to a simulated load trace which has a peak demand and annual energy very close to the 50% POE peak demand and energy forecast and has an annual load weighted price for Queensland very close to the median load weighted price across all 462 simulations. Once established, these contract volumes are then fixed across all 462 simulations when calculating the wholesale energy costs.

Contract volumes are calculated for each settlement class by assuming the following for each quarter:

- Base contract volume is set to equal the 80th percentile of the off-peak hourly demands for the quarter.
- Peak period contract volume is set to equal the 90th percentile of quarterly peak period demands minus the base contract volume.
- Cap contract volume set at 105 per cent of the quarterly peak demand minus the base and peak contract volumes.

3.2.5 Estimating contract prices

Contract prices for the 2013/14 year were estimated using d-cypha Trade daily settlement prices and trade volumes for all trades up until and including the cut-off date of 15 January 2013.

Table 7 shows the estimated quarterly swap and cap contract prices using the trade volume-weighted average of daily settlement prices.

Table 7 **Quarterly base, peak and cap estimated contract prices – 2013/14 ($/MWh)**

	Q3 2013	Q4 2013	Q1 2014	Q2 2014
Base	$53.53	$54.97	$65.77	$53.28
Peak	$60.12	$64.90	$87.88	$60.75
Cap	$3.32	$7.03	$12.87	$2.59

Data source: ACIL Tasman analysis using d-cypha Trade data up to, and including 15 January 2013.

Contract prices without carbon pricing

Contract prices *without* carbon pricing are estimated by subtracting the carbon price[8], adjusted for the estimated NEM intensity, from the trade-weighted contract prices in Table 7.

This method applies to the flat and peak contracts only. The carbon tax does not heavily influence prices greater than $300, and therefore cap contract prices are unchanged.

The NEM intensity is estimated using modelling output from the median case of the 462 simulations (the same case used to define the hedging strategy). The NEM intensity is equal to NEM total emissions divided by NEM sent-out dispatch, which is consistent with the emissions intensity published by AEMO. Estimates of the quarterly NEM emissions intensities are shown in Table 8.

[8] The carbon price in 2013/14 is the legislated carbon tax of $24.15/tCO2-e

Table 8 **Estimation of the NEM emissions intensity used to calculate contract prices without carbon pricing**

	NEM total emissions (million tonnes CO2-e)	NEM generation (GWh, sent-out)	NEM emissions intensity (tonnes CO2-e/ MWh, sent-out)
Q3 2013	42.31	47,651	0.89
Q4 2013	41.64	46,411	0.90
Q1 2014	41.99	46,366	0.91
Q2 2014	40.28	45,252	0.89

Note: Total emissions = combustion emissions + fugitive emissions

Data source: ACIL Tasman analysis based on the median case of the 462 simulations *of the low energy growth scenario*.

Table 9 shows the estimated quarterly swap and cap contract prices without carbon pricing.

Table 9 **Quarterly base, peak and cap estimated contract prices without carbon pricing – 2013/14 ($/MWh)**

	Q3 2013	Q4 2013	Q1 2014	Q2 2014
Base	$32.09	$33.30	$43.89	$31.78
Peak	$38.68	$43.23	$66.01	$39.25
Cap	$3.32	$7.03	$12.87	$2.59

Data source: ACIL Tasman analysis using d-cypha Trade data up to, and including 15 January 2013.

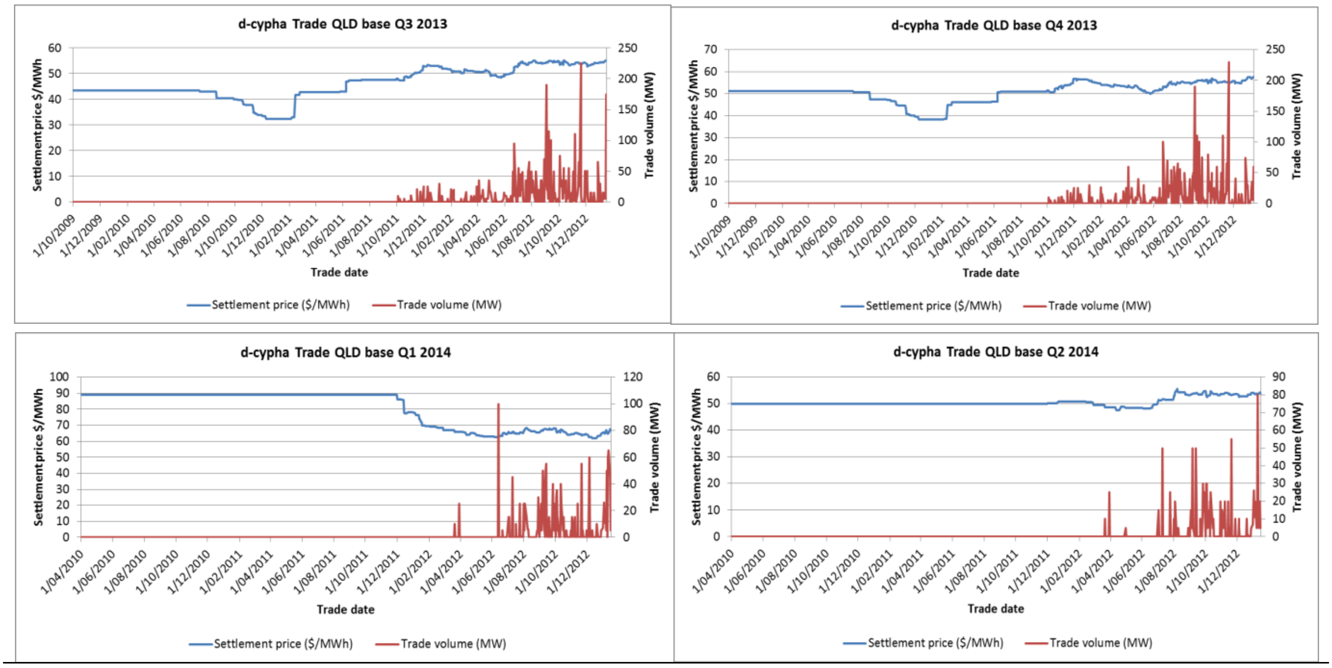
The following charts show daily settlement prices and trade volumes for d-cypha Trade quarterly base futures, peak futures and cap contracts.

Base contracts have traded strongly, with volumes of between 1,015MW (Q2 2014) and 3,999MW (Q3 2013). ACIL Tasman expects the Q1 2014 and Q2 2014 contracts to increase in trade volume throughout 2013, which is consistent with previous years, and hence the estimates will be updated for the Final Determination.

Peak futures have lower trade volumes of between 10MW (Q2 2014) and 85MW (Q4 2013). These volumes are consistent with peak contract trade volumes in previous years' Determinations. Peak contracts tend to be thinly traded more than 12 months out from the commencement of the contract period. Therefore ACIL Tasman expects Q2 2014 to have higher trade volumes from April 2013 , and hence the estimates will be updated for the Final Determination.

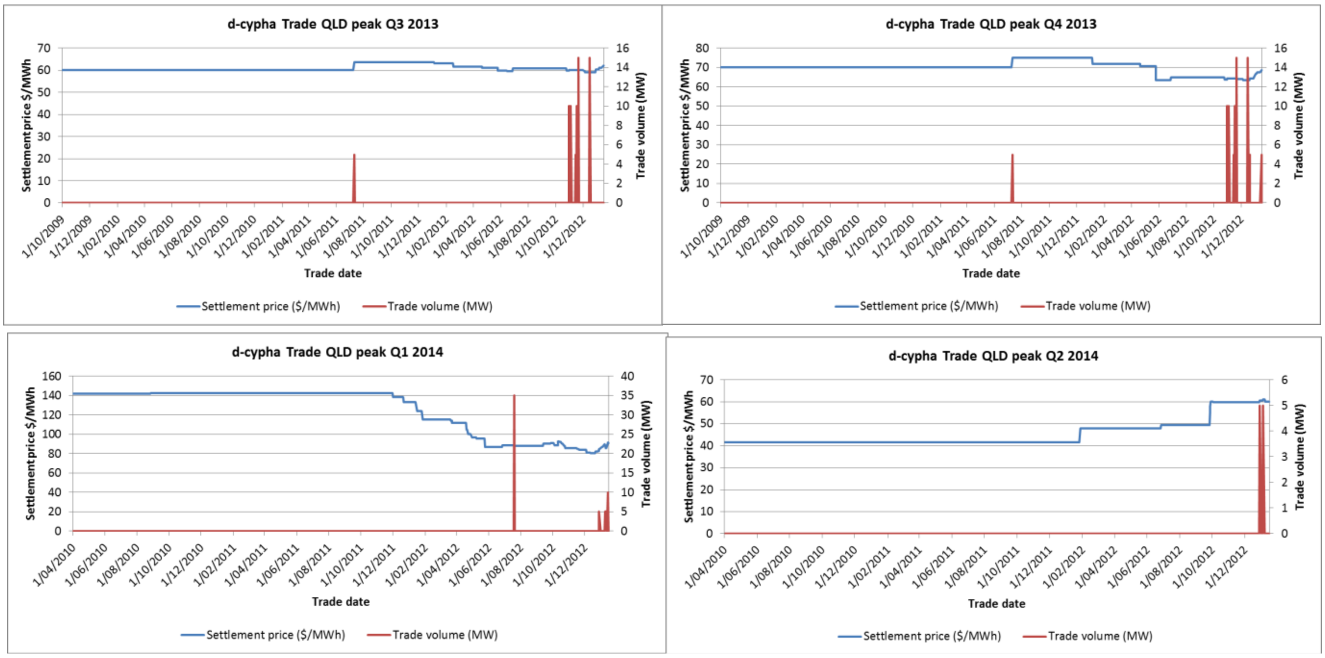
Cap contract trade volumes are consistent with previous years, and similar to the peak contracts, cap contracts tend to have greater trade volumes within 12 months from the commencement of the contract period.

Chart 1 **Time series of trade volume and price – d-cypha Trade QLD BASE futures for Q3 2013, Q4 2013, Q1 2014 and Q2 2014**



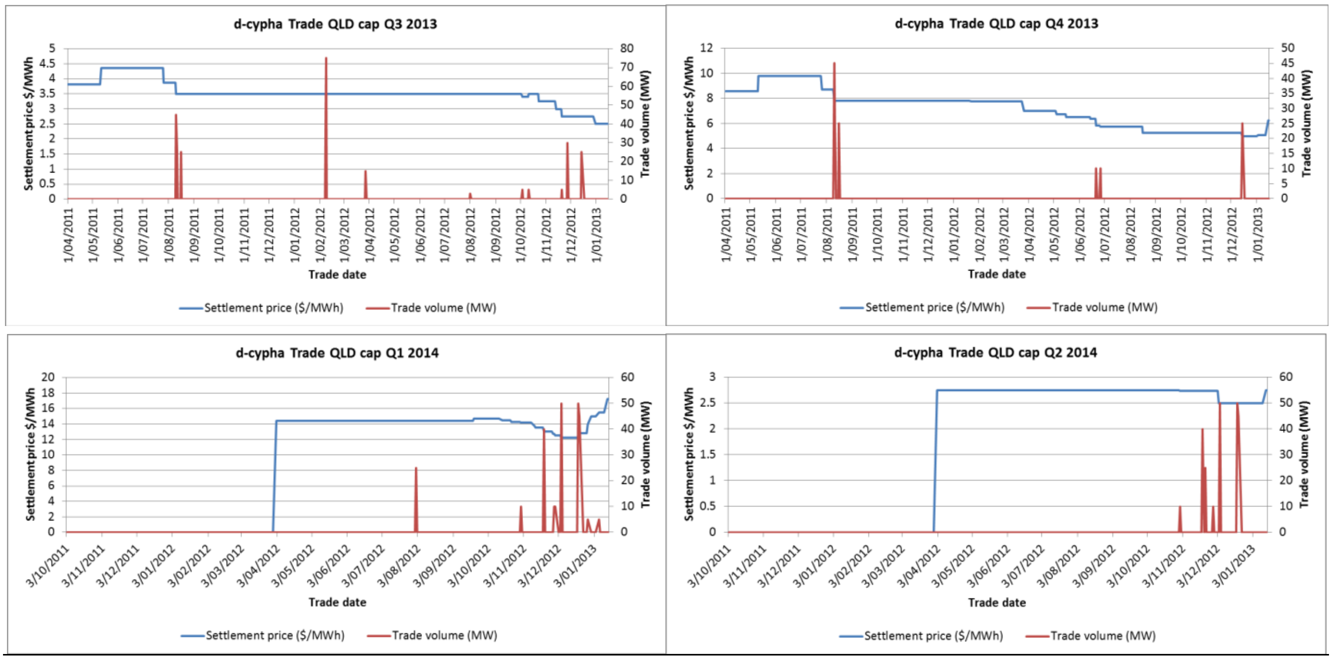
Source: d-cypha Trade data up to, and including 15 January 2013.

Chart 2 **Time series of trade volume and price – d-cypha Trade QLD PEAK futures for Q3 2013, Q4 2013, Q1 2014 and Q2 2014**



Source: d-cypha Trade data up to, and including 15 January 2013.

Chart 3 **Time series of trade volume and price – d-cypha Trade QLD $300 CAP contracts for Q3 2013, Q4 2013, Q1 2014 and Q2 2014**



Source: d-cypha Trade data up to, and including 15 January 2013.

TFS data

The trade-weighted price of 'Base with AFMA' contracts using broker trade data supplied by TFS, is $58.36/MWh for the financial year 2013/14 contract, which is around $1.50/MWh higher than the estimate using d-cypha Trade data. The TFS contracts have very few trades (50MW), while the d-cypha Trade contracts are heavily traded (10,000MW). Therefore, on the premise of greater volume of trades, ACIL Tasman has adopted the estimate based on d-cypha Trade data.

3.2.6 Application of transmission and distribution losses

Prices from the Queensland regional reference node must be adjusted for losses to the end-users. Distribution loss factors (DLF) for Energex and Ergon Energy east zone and load weighted Marginal Loss Factors (MLF) for transmission losses from the node to major supply points in the distribution networks are applied.

The MLF for each of the Energex and Ergon Energy's east zone area is based on the average energy-weighted marginal loss factor for the Energex and Ergon Energy east zone TNI's. This analysis resulted in a loss factor of 0.98 per cent for Energex and 4.61 per cent for the Ergon Energy east zone.

The distribution loss factor by settlement class for the Energex area and the Ergon energy east zone are taken from the AEMO Distribution Loss factors for 2012/13.

The estimated transmission and distribution loss factors for the settlement classes are shown in Table 10.

Table 10 **Estimated transmission and distribution loss factors for Energex and Ergon Energy's east zone**

Settlement classes	Distribution losses	Transmission losses	Total losses
Energex - NSLP - residential and small business and unmetered supply	6.2%	1.0%	7.2%
Energex - Control tariff 9000	6.3%	1.0%	7.3%
Energex - Control tariff 9100	6.3%	1.0%	7.3%
Ergon Energy - NSLP - SAC HV, CAC and ICC	3.8%	4.6%	8.6%
Ergon Energy - NSLP - SAC demand and street lighting	7.8%	4.6%	12.8%

Data source: ACIL Tasman analysis on each of the Queensland TNIs, Queensland MLFs and Energex and Ergon Energy east zone DLFs for 2012/13 from AEMO.

The losses are accounted for by dividing the WEPC at the node by one minus the percentage loss.

3.2.7 Calculation of wholesale energy costs for 2013-14

Using the contract prices and volumes with the projected hourly pool prices for the 462 simulations in the hedge model provides 462 estimates of the wholesale energy cost for each settlement class.

In recognition that there is some residual volume and price risk retained in the hedging strategy, the 95th percentile of the 462 simulated annual hedged prices is used as the estimate of the cost of energy in 2013-14.

For the control load tariffs ACIL Tasman used the hedge model to calculate the cost of supplying the NSLP with and without the control loads and the difference was taken as the cost for the controlled loads. The price per MWh for controlled loads is then calculated by dividing the cost difference by estimated energy under the controlled load.

3.3 Data sources

3.3.1 Generation cost and other data

The generator information used in the market modelling covers fuel and variable O&M costs, installed capacities, efficiencies, emission factors, planned and forced outage rates, auxiliary use, portfolio ownership structure, contract cover and minimum generation levels.

These data are contained in the generator data base used in the *PowerMark* modelling of pool prices. The estimates contained in this data base have been developed over the past 15 years and have been scrutinised by a wide variety of clients over this period. The sources of this data are many and include:

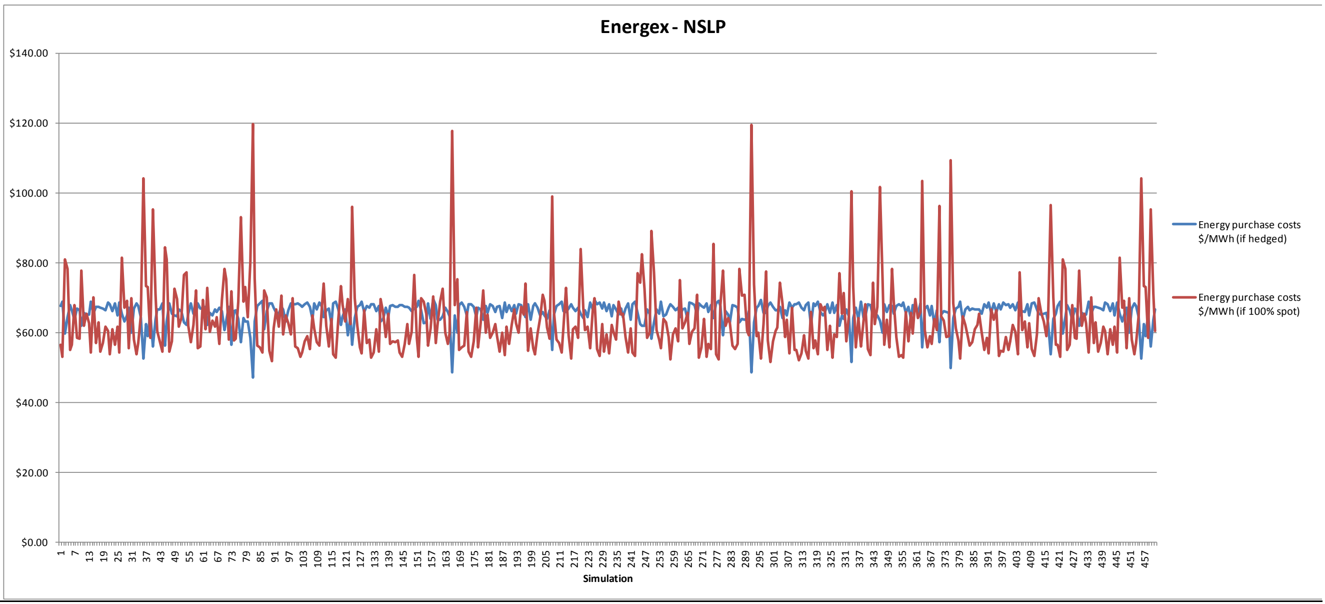
- annual reports
- gas price modelling using *GasMark*
- announced contractual arrangements for fuel
- ACIL Tasman estimates
- Non-sensitive information provided by clients
- AEMO reports

Detailed data is provided in Appendix C.

3.4 Summary of WEC estimates

Figure 4 demonstrates that there is limited variation in the WEC across the 462 simulation years when applying the hedging strategy to the Energex NSLP, when compared with the non-hedged price variation. This indicates that the hedging strategy while relatively unsophisticated is a reasonable approach to hedging the retailer load. Although the unhedged approach yields lower prices in general, the volatility in outcomes represents significant risk to a retailer. A similar conclusion holds for the other settlement classes.

Figure 4 **Price outcomes ($/MWh, nominal) of 462 simulations for the Energex NSLP - 2013-14**



Note: Projected prices based on 462 simulations of the low energy growth scenario
Data source: ACIL Tasman analysis

Table 11 shows the results for the WEC modelling for the Draft Determination. It includes an allowance for the transmission and distribution losses and the estimate of the cost at the customer terminals.

Table 11 **Estimated WEC ($/MWh, nominal) for 2013-14 - Draft Determination**

Settlement class	Wholesale energy cost at the regional reference node ($/MWh)	Allowance for transmission and distribution losses	Wholesale energy costs at the customer terminal ($/MWh)
Energex - NSLP - residential and small business	$68.59	7.2%	$73.94
Energex - Control tariff 9000	$46.84	7.3%	$50.55
Energex - Control tariff 9100	$57.15	7.3%	$61.68
Energex - NSLP - unmetered supply	$68.59	7.2%	$73.94
Ergon Energy - NSLP - SAC HV, CAC and ICC	$63.33	8.6%	$69.28
Ergon Energy - NSLP - SAC demand and street lighting	$63.33	12.8%	$72.60

Note: Projected prices based on the 95th percentile of the 462 simulations of the low energy growth scenario
Data source: ACIL Tasman analysis

Table 12 summarises the WEC in the case where the price on carbon is excluded.

Table 12 **Estimated WEC ($/MWh, nominal) for 2013-14 - excluding a price on carbon - Draft Determination**

Settlement class	Wholesale energy cost at the regional reference node ($/MWh)	Allowance for transmission and distribution losses	Wholesale energy costs at the customer terminal ($/MWh)
Energex - NSLP - residential and small business	$46.88	7.2%	$50.54
Energex - Control tariff 9000	$25.07	7.3%	$27.06
Energex - Control tariff 9100	$35.74	7.3%	$38.58
Energex - NSLP - unmetered supply	$46.88	7.2%	$50.54
Ergon Energy - NSLP - SAC HV, CAC and ICC	$41.56	8.6%	$45.46
Ergon Energy - NSLP - SAC demand and street lighting	$41.56	12.8%	$47.64

Note: Projected prices based on the 95th percentile of the 462 simulations of the low energy growth scenario

Data source: ACIL Tasman analysis

4 Estimation of other energy costs

The other energy costs (OEC) estimates provided in this section consist of:

- Costs associated with compliance with the Renewable Energy Target (RET) encompassing:
  - LRET
  - SRES
- Costs of compliance with the Queensland Gas Scheme
- Market fees and charges including:
  - NEM management fees
  - Ancillary services costs
- Pool and hedging prudential costs.

4.1 Renewable Energy Target scheme

The RET scheme consists of two elements – the LRET and the SRES. Liable parties (i.e. all electricity retailers[9]) are required to comply and surrender certificates for both SRES and LRET.

To determine the costs to retailers of complying with both the LRET and SRES, ACIL Tasman has used the following:

- Large-scale Generation Certificate (LGC) market prices from AFMA[10]
- Adjusted LRET targets for 2013 and 2014 of 19,088 GWh and 16,950 GWh respectively, as published by the Clean Energy Regulator (CER)
- An ACIL Tasman estimate for the Renewable Power Percentage (RPP) for 2013 and 2014 based on the inferred liable energy from the CER's non-binding estimate for the STP for these years. These RPP estimates are set out in Table 13[11]
- CER's non-binding estimate for Small-scale Technology Percentage (STP) of 18.76 and 7.69 per cent for 2013 and 2014 respectively[12]

9 Emissions Intensive Trade Exposed (EITE) industries such as aluminium are wholly or partially exempted and receive Partial Exemption Certificates (PEC) to be surrendered to the named liable entity.

10 AFMA data includes weekly settlement prices to January 2013, which is the cut-off date for all relevant market-based data used in this Draft Determinationfor 2013/14 tariffs.

11 Note that these estimates differ slightly from the Default RPP values for future years calculated in accordance with Section 39 (2)(b) of the Act

12 Published on 19 October 2012

- CER clearing house price for 2013 and 2014 for Small-scale Technology Certificates (STCs) of $40/MWh.

4.1.1 LRET

To translate the aggregate LRET target for any given year into a mechanism such that liable entities under the scheme may determine how many LGCs they must purchase and acquit, the LRET legislation requires the CER to publish the RPP by the 31 March within the compliance year.

The RPP is determined ex-ante by the CER and represents the relevant year's LRET target (in fixed GWh terms) as a percentage of the estimated volume of liable electricity consumption throughout Australia in that year.

The estimated cost of compliance with the LRET scheme is derived by applying the RPP to the determined LGC price to establish the cost per MWh of liable energy supplied to customers. Since the cost is expressed as a cost per MWh, it is applicable across all retail tariffs.

Spot and futures markets exist for LCGs. ACIL Tasman recognises that the volume of LGC trades through the spot market comprises a relatively small proportion of overall liabilities and might not be a reliable indicator of costs. However, the relatively low volume of trading does not necessarily mean that traded prices are an unreliable source on which to base the estimation of scheme costs.

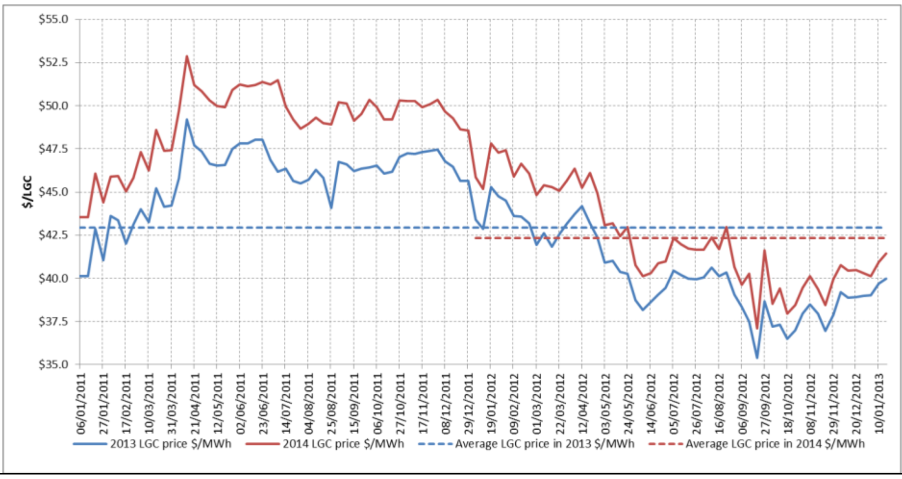
As discussed in our advice for the 2012-13 Determination, ACIL Tasman is satisfied that using the forward looking weekly market prices for LGCs published by the Australian Financial Markets Association (AFMA) [13] provides a sound estimate for the cost of a retailer meeting the LRET in 2013-14.

The LGC price used in assessing the cost of the scheme for 2013-14 is found by averaging the futures prices for 2013 and 2014 during the two years prior to the commencement of 2013 and 2014. This assumes that LGC coverage is built up over a two year period (see Figure 5). The average LGC prices calculated from the AFMA data are $42.93/MWh for 2013 and $42.32/MWh for 2014**:**

- 2013 is based on prices starting on 6 January 2011 capturing 107 weeks
- 2014 is based on prices starting on 5 January 2012 capturing 55 weeks.

[13] The Australian Financial Markets Association (AFMA) publishes reference information on Australia's wholesale over-the-counter (OTC) financial market products. This includes a broker survey of bids and offers for LGCs, STCs and other environmental products which is published weekly.

Figure 5 **LGC futures prices for 2013 and 2014 (nominal $/LGC)**



Data source: AFMA

The RPP component of the calculation is estimated using data published by CER. The non-binding STP estimate published on 19 October 2012 under section 40B of the Act provides the percentage as a proportion of total estimated liable electricity for both 2013 and 2014, as well as the equivalent number of STCs. Using this data, the CER's current view of the total estimated liable energy is derived. Combining the total estimated liable energy with the legislated target, ACIL Tasman then calculated the implied RPP (see Table 13). The decline in the RPP from 2013 to 2014 is due to the lower legislated target of 16,950 GWh in 2014 (2,138 GWh lower than 2013).

Table 13 **Calculation of the 2013 and 2014 RPP**

	Non-binding	Non-binding
	2013	2014
Small-scale Technology Percentage (%)	18.76%	7.69%
Equivalent to ('000) STCs	34,457	14,485
Estimated total liable energy (GWh)	183,672.71	188,361.51
LRET target (GWh)	19,088	16,950
Implied RPP (%)	10.39%	9.00%

Note: The targets for 2013 and 2014 have been adjusted for the inclusion of eligible waste coal mine gas in accordance with Section 40 (2)-(5) of the Act

Data source: CER, ACIL Tasman analysis

Therefore, ACIL Tasman estimates the cost of complying with the LRET scheme to be $4.13/MWh in 2013-14 as shown in Table 14.

Table 14 **Estimated cost of LRET – Draft Determination 2013-14**

	2013	2014	Cost of LRET Draft Determination 2013-14
Estimated RPP %	10.39%	9.00%	
Average LGC price ($/LGC, nominal)	$42.93	$42.32	
Cost of LRET ($/MWh, nominal)	$4.46	$3.81	$4.13

Data source: CER, AFMA, ACIL Tasman analysis

4.1.2 SRES

The cost of SRES for calendar years 2013 and 2014 is calculated by applying the CER published STP to the STC price. The average of these calendar year costs is then used to obtain the estimated cost for 2013-14.

The non-binding STP published on 19 October 2012 under section 40B of the Act by CER was as follows:

- 18.76 per cent for 2013 (equivalent to 34.457[14] million STCs as a proportion of total estimated liable electricity for the 2013 year)
- 7.69 per cent for 2014 (equivalent to 14.485 million STCs as a proportion of total estimated liable electricity for the 2014 year).

ACIL Tasman is aware that these estimates have been compiled based on the expectation that the Solar Credits multiplier of two was to expire on 30 June 2013. Since these estimates were compiled the Minister for Climate Change and Energy Efficiency announced the phase out of the Solar Credits multiplier ahead of schedule, on 1 January 2013[15]. This announcement should result in less solar installations but could also create a short term solar installation bubble similar to that experienced in Queensland towards the end of 2012.

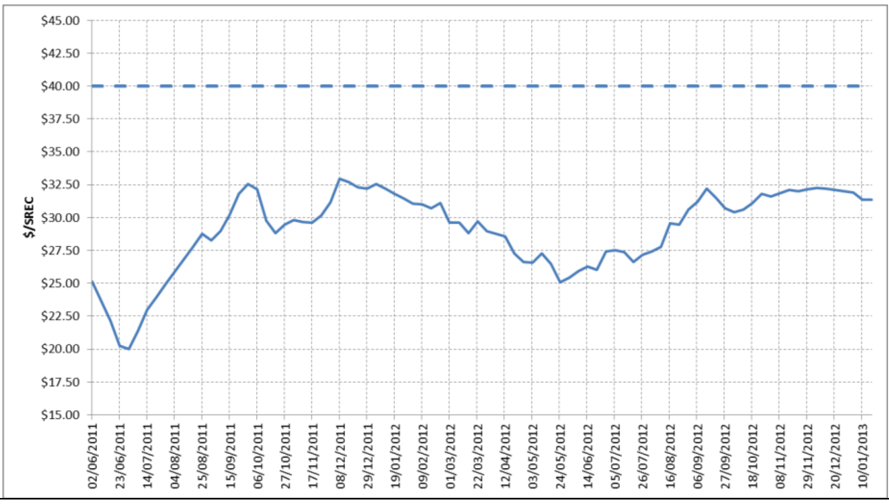
The 'STC clearing house' is a mechanism designed to facilitate the exchange of STCs between buyers and sellers at a fixed price of $40, with the purpose to cap the scheme at a predetermined price as well as deliver a set subsidy to entities creating STCs. The clearing house is a voluntary mechanism and liable entities can source STCs through secondary markets. In practice, the annual oversupply of STCs since the inception of the SRES has resulted in a secondary market STC price of $25 to $33 over the last 12 months (see Figure 6).

---

14 Includes an estimate of 15.993 million excess STCs created in 2012 over the 22.306 million estimate used in setting the 2012 STP (which totalled 44.786 with the 2011 surplus added). It also includes an updated estimated total of 18.464 million STCs to be created in 2013.

15 Solar Credits phase out to moderate price impact retrieved from http://www.climatechange.gov.au/minister/greg-combet/2012/media-releases/November/MR-307-12.aspx on 1 February 2013

Figure 6 **Small-scale Technology Certificate spot price**



Data source: AFMA

In the estimation of STC prices there are two distinct options:

- Use the nominal clearing house price of $40/STC
- Estimate an average price for STCs on the secondary market over 2013-14.

The first option is relatively straight forward as this price is set within the legislation and is held fixed in nominal terms. It provides a price cap for the scheme.

The second option of a 'market price' approach would be relevant where supply was expected to continue to significantly exceed forecast demand. The removal of the solar credits multiplier and reform of feed-in-tariffs suggest that this is less likely. In addition while not necessarily linearly related, lower costs would imply higher demand than assumed in the non-binding CER estimates which would be expected to largely offset lower prices.

For these reasons ACIL Tasman continues to use the best published CER estimates and the clearing house price of $40 for STCs in determining the contribution to energy costs. We estimate the cost of complying with SRES to be $5.29/MWh in 2013-14 as set out in Table 15.

Table 15 **Estimated cost of SRES – Draft Determination 2013-14**

	2013	2014	Cost of SRES Draft Determination 2013-14
STP %	18.76%	7.69%	
STC clearing house price ($/STC, nominal)	$40.00	$40.00	
Cost of LRET ($/MWh, nominal)	$7.50	$3.08	$5.29

Data source: CER, ACIL Tasman analysis

Combining the LRET and SRES costs for both schemes yields a total cost of $9.42/MWh for 2013-14.

4.2 Queensland Gas Scheme

In order to estimate the cost of the GECs scheme, ACIL Tasman continues to employ the same methodology used in the 2012-13 Final Determination.

The methodology relies on a 4-year average of the weekly GEC prices as published by AFMA. This methodology has been chosen since there is no available information on the volumes of GECs being traded or if any of the $15 legacy contracts still apply. The selection of the time interval attempts to capture the whole range of hedging strategies.

The AFMA weekly GEC prices have been averaged over an extended period of 209 weeks or 4 years as follows:

- 2013 is based on prices starting on January 2008
- 2014 is based on prices starting on January 2009.

The cut-off date for the AFMA data used in this Report is January 2013.

The average GEC prices calculated from the AFMA data are $4.78/MWh for 2013 and $3.21/MWh for 2014. The average of these prices results in a GEC price of $4.00/MWh which when multiplied by the 15% liability results in a GEC allowance of $0.60/MWh for 2013-14 as set out in Table 16.

Table 16 **Estimated cost ($/MWh, nominal) of Queensland Gas Scheme using AFMA data**

	GEC allowance ($/MWh)
Total cost of Queensland Gas Scheme	$0.60

Data sources: ACIL Tasman analysis based on data from AFMA for prices and Queensland Department of Energy and Water Supply for the prescribed percentage.

4.3 NEM management fees

NEM participant and FRC fees are payable by retailers to AEMO to cover operational expenditure. The fees also cover costs associated with the National Transmission Planner, National Smart Metering and the Electricity Consumer Advocacy Panel.

Using estimates in AEMO's *Electricity Final Budget and Fees for 2012-13*, the estimated total NEM fee for 2013-14 is $0.40/MWh.

Table 17 **Estimated NEM fees ($/MWh, nominal)**

Cost category	Fees ($/MWh)
Market participant fees	$0.34
FRC fees	$0.06
Total NEM fees	$0.40

Data source: AEMO Electricity Final Budget and Fees for 2012-13

4.4 Ancillary services

AEMO provides weekly aggregated settlements data for ancillary service payments in each interconnected region. Using the average costs over the preceding 52 weeks of currently available NEM ancillary services data as a basis for 2013-14, the cost of ancillary services is estimated to be $0.31/MWh.

Table 18 **Estimated ancillary services charges ($/MWh, nominal)**

	Fees ($/MWh)
Ancillary services	$0.31

Data source: ACIL Tasman analysis based on AEMO Ancillary Services payment data

4.5 Prudential costs

This section covers cost estimates for AEMO and hedge prudential costs

4.5.1 AEMO prudentials

AEMO calculates a maximum credit limit for each counterparty in order to determine the requirement for any or a combination of:

- bank guarantees
- reallocation certificates
- prepayment of cash.

There is no fundamental requirement to reallocate prudential obligations – it is a retailer's choice to do so. Assuming no reallocation and no vertical integration (either owned generation or PPAs), a retailer is required to provide suitable guarantees to the AEMO assessed maximum credit limit (MCL) which is calculated as follows:

MCL = (Average daily load x Average future price x Volatility factor x Loss factor x (GST + 1) x 42 days

Taking a 1 MWh average daily load and assuming the following inputs:

- a future pool price estimate for the 95th percentile of $65.06
- a volatility factor of 1.5 (as proposed by QEnergy)
- Loss factor of 1.5

results in an MCL of $4,734.

However as this applies for a rolling 42 days it actually covers 42 MWh of retailer purchases. Hence the portion of the MCL applicable to each MWh is $4,734/42 = $112.71.

The cost of funding a bank guarantee for the MCL associated with the single MWh is assumed to be a 2.5% annual charge[16] for 42 days or 2.5%/(42/365) = 0.288%. Applying this funding cost to the single MWh charge of $112.71 gives $0.324/MWh.

Table 19 **Estimated ancillary services charges ($/MWh, nominal)**

	Cost estimate ($/MWh)
AEMO prudentials	$0.324

Data source: ACIL Tasman analysis based on AEMO Ancillary Services payment data

4.5.2 Hedge prudentials

ACIL Tasman has relied on the futures market to determine hedging costs. The futures market includes prudential obligations by requiring entities to lodge initial margins (we assume cash) when contracts are purchased or sold. We understand that the cash that is lodged as an initial margin receives a money market related return which offsets some of the funding costs. The current money market rate is around 3%. Additional margin calls may apply where contracts move unfavourably for the purchaser or seller. However, as these may be favourable or unfavourable we have assumed that they average out over time.

We understand that the initial margin is set based on three parameters being:

- the price scanning range (PSR) expressed as a percentage of the contract face value and currently set at around 5.5% on average for a base contract
- the intra commodity spread charge currently set at $2,200 for a base contract of 1 MW for a quarter
- the spot isolation rate currently set at $400

Using an annual average futures price of $56.85[17] and applying the above factors gives an average initial margin for each quarter of around $9,500 for a 1 MW quarterly contract. In order to allow for some ongoing future uncertainty we have rounded this to $10,000 per 1 MW quarterly contract. Dividing this by

16 This is the handling charge for a guarantee facility which is not drawn down.

17 Average annual price for base load futures costs used in estimating WEC.

the average hours in a quarter then gives an initial margin of $4.57 per MWh. The funding cost is 9.72% (the approved WACC for Energex as proposed by QEnergy) but this is adjusted for an assumed 3% return on cash lodged with the clearing house and hence gives a net funding cost of 6.72%. Applying 6.72% to the initial margin per MWh gives a prudential cost for hedging of $0.307/MWh.

ACIL Tasman notes that the prudential requirements are higher for peak and cap contracts but where contracts are bought across the various types a discount is applied to the overall margin which largely offsets the higher individual contract initial margins (reflecting the diversification of risk). Hence ACIL Tasman considers that the base load assessment is a reasonable reflection of the prudential obligations faced by retailers.

4.5.3 Total prudentials

Adding the AEMO prudentials and hedge prudentials gives a total prudential requirement as set out in Table 20:

Table 20 **Total prudential costs ($/MWh)**

Cost category	Draft Determination 2013-14
AEMO pool	$0.324
Hedge	$0.307
Total	$0.631

4.6 Summary of other energy cost estimates

In summary, the 'other energy costs' components for 2013-14 are estimated to be $11.36/MWh. These costs are summarised in Table 21.

Table 21 **Summary of OEC – at the regional reference node ($/MWh)**

Cost category	Fees ($/MWh)
Renewable Energy Target	$9.42
Queensland Gas Scheme	$0.60
NEM fees	$0.40
Ancillary services	$0.31
Prudential	$0.63
Total other energy costs	$11.36

Note: All costs are presented at the Queensland regional reference node.
Data source: ACIL Tasman analysis

5 Summary of energy costs

Estimated total energy costs (TEC) for the Draft Determination for the settlement classes in the Energex area and Ergon Energy are presented in Table 22 and Table 23 - with and without carbon respectively. The estimated costs in the table include both the WEC and the OEC.

Table 22 **Estimated TEC ($/MWh, nominal) for 2013-14 - Draft Determination**

Settlement class	Wholesale energy cost at the regional reference node ($/MWh)	Renewable energy and market fees at the regional reference node ($/MWh)	Allowance for transmission and distribution losses	Total energy costs at the customer terminal ($/MWh)
Energex - NSLP - residential and small business	$68.59	$11.36	7.2%	$86.18
Energex - Control tariff 9000	$46.84	$11.36	7.3%	$62.81
Energex - Control tariff 9100	$57.15	$11.36	7.3%	$73.94
Energex - NSLP - unmetered supply	$68.59	$11.36	7.2%	$86.18
Ergon Energy - NSLP - SAC HV, CAC and ICC	$63.33	$11.36	8.6%	$81.70
Ergon Energy - NSLP - SAC demand and street lighting	$63.33	$11.36	12.8%	$85.62

Note: Projected prices based on the 95th percentile of the 462 simulations of the low energy growth scenario

Data source: ACIL Tasman analysis

Table 23 **Estimated TEC ($/MWh, nominal) for 2013-14 - excluding a price on carbon - Draft Determination**

Settlement class	Wholesale energy cost at the regional reference node ($/MWh)	Renewable energy and market fees at the regional reference node ($/MWh)	Allowance for transmission and distribution losses	Total energy costs at the customer terminal ($/MWh)
Energex - NSLP - residential and small business	$46.88	$11.36	7.2%	$62.78
Energex - Control tariff 9000	$25.07	$11.36	7.3%	$39.31
Energex - Control tariff 9100	$35.74	$11.36	7.3%	$50.83
Energex - NSLP - unmetered supply	$46.88	$11.36	7.2%	$62.78
Ergon Energy - NSLP - SAC HV, CAC and ICC	$41.56	$11.36	8.6%	$57.88
Ergon Energy - NSLP - SAC demand and street lighting	$41.56	$11.36	12.8%	$60.66

Note: Projected prices based on the 95th percentile of the 462 simulations of the low energy growth scenario

Data source: ACIL Tasman analysis

Appendix A Ministerial Delegation

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 no later than 15 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.

DATED this 5th day of September 2012.

[redacted]

SIGNED by the Honourable
Mark McArdle,
Minister for Energy and Water Supply) (signature)

Appendix B Consultancy Terms of Reference

Terms of Reference

Review of Regulated Retail Electricity Tariffs and Prices for 2013-14

Assessment of Energy Costs and Tariff Structure

31 October 2012

1. Project Background

On 5 September 2012, the Minister for Energy and Water Supply provided the Authority a Delegation requiring it to determine regulated retail electricity prices (notified prices) for a three-year period from 1 July 2013 to 30 June 2016 (**Attachment 1**).

While the task is delegated for three years (rather than a one-year period as previously), the Authority is still required to determine prices annually. The first determination is to apply from 1 July 2013 to 30 June 2014.

The Authority will require the assistance of a consultant to estimate the cost of energy for notified prices.

2. Outline of Consultancy

The consultant will be required to provide expert advice to the Authority on the energy costs to be incurred by a retailer to supply customers on notified prices for 2013-14. In preparing its advice, the consultant must have regard to the actual costs of making, producing or supplying the goods or service.

The Authority will require 2013-14 estimates for:

(a) wholesale energy costs;

(b) the costs of complying with state and federal government policies such as the Queensland Gas Scheme, the Enhanced Renewable Energy Target Scheme and the carbon tax;

(c) NEM fees and ancillary services charges; and

(d) losses in the transmission and distribution of electricity to customers.

The Authority is also offering an 'in principle' agreement for the consultant to be engaged to provide similar advice for its 2014-15 and 2015-16 reviews. This offer is subject to the consultant not undertaking work over the three-year period that might be seen as a conflict of interest or could otherwise preclude their appointment as the Authority's advisor. Appointment in each year would of course be subject to the proposed cost being reasonable given the nature of the task for the year and the cost in previous years.

3. Deliverables

The consultant will be required to provide a series of deliverables and take part in workshops, consultations and meetings. While Table 1 outlines the mandatory deliverables for the

- 1 -

consultancy, there may be additional requests made of the consultants from time to time as needed by the Authority.

Table 1: Timetable for the Consultancy

Deliverable	***Task***	***Due date***
Stakeholder Workshop	• Conduct a workshop with interested parties on the consultant's proposed approach to calculating energy costs	Early December 2012
Draft Report	• Address submissions on the Authority's Interim Consultation Paper and issues raised in the Stakeholder Workshop • Outline the consultant's approach • Provide draft cost estimates	7 December 2012
Final Report	• Address submissions on the Draft Report • Outline the consultant's final approach • Provide final cost estimates	5 April 2013

4. Resources/Data Provided

The consultant will be required to source modelling data and information independently.

Additional information relevant to this consultancy may be found in the Authority's publications which can be obtained from the Authority's website.

5. Project Time Frame

The consultancy will commence in mid October 2012 and is expected to be completed by 31 May 2013.

6. Proposal Specifications and Fees

The proposal should:

- include the name, address and legal status of the tenderer;
- provide the proposed methods and approach to be applied;
- provide a fixed price quote for the provision of the services detailed herein; and
- nominate the key personnel who will be engaged on the assignment together with the following information:
  - name;
  - professional qualifications;

- general experience and experience which is directly relevant to this assignment;
- expected time each consultant will work on the project; and
- standard fee rates for any contract variations.

The fee quoted is to be inclusive of all expenses and disbursements. A full breakdown of consultancy costs is required with staff costs reconciled to the consultancy work plan.

Total payment will be made within 28 days of receiving an invoice at the conclusion of the consultancy.

7. Contractual Arrangements

This consultancy will be offered in accordance with the Authority's standard contractual agreement.

This agreement can be viewed at http://www.qca.org.au/about/consultancyagreement.php

8. Reporting

The consultant will be required to provide the Authority with progress reports on an "as needs" basis or at least weekly and drafts of final reports will be required prior to project completion. If necessary, the consultant should advise at the earliest opportunity any critical issues that may impede progress of the consultancy, particularly issues that impact on the successful delivery of the Consultancy Objectives outlined in Section 2 above.

9. Confidentiality

Under no circumstance is the selected consultant to divulge any information obtained from any distributor, retailer or the Authority for the purposes of this consultancy to any party, other than with the express permission of the distributor or retailer concerned, and the Authority.

10. Conflicts of Interest

For the purpose of this consultancy, the consultant is required to affirm that there is no, and will not be any, conflict of interest as a result of this consultancy.

11. Authority Assessment of Proposal

The proposal will be assessed against the following criteria:

- understanding of the project;
- skills and experience of the firm and team;
- the proposed methods and approach;
- capacity to fulfil the project's timing requirements; and
- value for money.

In making its assessment against the criteria, the Authority will place most weight on relevant experience of the team members involved and the proposed method for the completion of the task.

12. Insurance

The consultant must hold all necessary workcover and professional indemnity insurance.

13. Quality Assurance

The consultant is required to include details of quality assurance procedures to be applied to all information and outputs provided to the Authority.

14. Lodgement of Proposals

Proposals are to be lodged with the Authority by 19 October 2012.

For further information concerning this consultancy, please contact Charles Millsteed, Energy Team Leader on (07) 3222 0543.

Proposals should be submitted to:

The Chief Executive Officer

Queensland Competition Authority
GPO Box 2257
Brisbane Qld 4001

Phone: (07) 3222 0555
Fax: (07) 3222 0599
Email: electricity@qca.org.au

Appendix C Detailed modelling assumptions

This appendix provides detailed inputs to the PowerMark model used in the estimates of energy costs.

C.1 Fuel Prices

Fuel prices assumed for the Queensland generators is shown in Table C1.

Table C1 **Fuel prices assumed for Queensland power stations ($/GJ, nominal - by calendar year**

Generator	Fuel	2013	2014
Barcaldine	Natural gas	$7.11	$7.26
Braemar 1	Natural gas	$2.87	$2.95
Braemar 2	Natural gas	$3.11	$4.59
Callide B	Black coal	$1.44	$1.47
Callide C	Black coal	$1.44	$1.47
Collinsville	Black coal	$2.30	$2.35
Condamine	Natural gas	$2.26	$8.15
Darling Downs	Natural gas	$4.31	$5.05
Gladstone	Black coal	$1.71	$1.75
Kogan Creek	Black coal	$0.82	$0.84
Mackay GT	Liquid Fuel	$33.07	$33.90
Millmerran	Black coal	$0.93	$0.95
Mt Stuart	Liquid Fuel	$33.07	$33.90
Oakey	Natural gas	$4.53	$4.64
Roma	Natural gas	$5.85	$6.44
Stanwell	Black coal	$1.53	$1.56
Swanbank B	Black coal	$3.90	$3.74
Swanbank E	Natural gas	$3.87	$4.05
Tarong	Black coal	$1.10	$1.12
Tarong North	Black coal	$1.10	$1.12
Townsville	Natural gas	$4.33	$4.43
Yarwun	Natural gas	$3.80	$3.88

Data source: ACIL Tasman research based on a wide variety of data sources and fuel market modelling

C.2 Plant outages

Planned and forced outages assumed for the Queensland plant are shown in Table C2.

Table C2 **Planned and forced outages for Queensland power stations**

Generator	Forced outage rate	Planned outage schedule
Barcaldine	2.5%	1 month every two years
Barron Gorge	1.5%	1 month every two years
Braemar 1	1.5%	1 month every four years
Braemar 2	1.5%	1 month every four years
Callide B	4.0%	1 month every four years
Callide C	6.0%	1 month every two years
Condamine	1.5%	1 month every two years
Darling Downs	3.0%	1 month every two years
Gladstone	4.0%	1 month every two years
Kareeya	1.5%	1 month every four years
Kogan Creek	4.0%	1 month every two years
Mackay GT	1.5%	1 month every four years
Millmerran	5.0%	1 month every two years
Mt Stuart	2.5%	1 month every four years
Oakey	2.0%	1 month every four years
Roma	3.0%	1 month every four years
Stanwell	2.5%	1 month every two years
Swanbank E	3.0%	1 month every four years
Tarong	3.0%	1 month every four years
Tarong North	3.0%	1 month every two years
Townsville	2.3%	1 month every four years
Yarwun	3.0%	1 month every four years

Data source: ACIL Tasman research based on a wide variety of data sources including AEMO

Summary data for Queensland power stations is provided in Table C3.

Table C3 **Details of Queensland generators used in pool price modelling for 2013-14**

Portfolio	Generator	DUID	Gen Type	Fuel	Capacity (MW)	Min Gen (MW)	Auxiliaries (%)	Thermal efficiency HHV (%) sent-out	Combustion emission factor (kg CO2-e/GJ of fuel)	Fugitive emission factor (kg CO2-e/GJ of fuel)	VOM ($/MWh sent-out, 2012 $)
AGL	Oakey	OAKEY1	Gas turbine	Natural gas	141	0	1.5%	32.6%	0.0513	0.0054	$9.74
AGL	Oakey	OAKEY2	Gas turbine	Natural gas	141	0	1.5%	32.6%	0.0513	0.0054	$9.74
AGL	Townsville	YABULU	Gas turbine combined cycle	Coal seam methane	160	133	3.0%	46.0%	0.0513	0.0054	$1.07
AGL	Townsville	YABULU2	Gas turbine combined cycle	Coal seam methane	80	67	3.0%	46.0%	0.0513	0.0054	$1.07
Alinta	Braemar 1	BRAEMAR1	Gas turbine	Natural gas	168	90	1.5%	30.0%	0.0513	0.0054	$8.03
Alinta	Braemar 1	BRAEMAR2	Gas turbine	Natural gas	168	90	1.5%	30.0%	0.0513	0.0054	$8.03
Alinta	Braemar 1	BRAEMAR3	Gas turbine	Natural gas	168	90	1.5%	30.0%	0.0513	0.0054	$8.03
CS Energy	Callide B	CALL_B_1	Steam turbine	Black coal	350	200	7.0%	36.1%	0.095	0.002	$1.22
CS Energy	Callide B	CALL_B_2	Steam turbine	Black coal	350	200	7.0%	36.1%	0.095	0.002	$1.22
CS Energy	Callide C	CPP_3	Steam turbine	Black coal	405	200	4.8%	36.5%	0.095	0.002	$2.77
CS Energy	Gladstone	GSTONE1	Steam turbine	Black coal	280	110	5.0%	35.2%	0.0921	0.002	$1.21
CS Energy	Gladstone	GSTONE2	Steam turbine	Black coal	280	110	5.0%	35.2%	0.0921	0.002	$1.21
CS Energy	Gladstone	GSTONE3	Steam turbine	Black coal	280	110	5.0%	35.2%	0.0921	0.002	$1.21
CS Energy	Gladstone	GSTONE4	Steam turbine	Black coal	280	110	5.0%	35.2%	0.0921	0.002	$1.21
CS Energy	Gladstone	GSTONE5	Steam turbine	Black coal	280	110	5.0%	35.2%	0.0921	0.002	$1.21
CS Energy	Gladstone	GSTONE6	Steam turbine	Black coal	280	110	5.0%	35.2%	0.0921	0.002	$1.21
CS Energy	Kogan Creek	KPP_1	Steam turbine	Black coal	750	350	8.0%	37.5%	0.094	0.002	$1.28
CS Energy	Wivenhoe	W/HOE#1	Hydro	Hydro	250	0	1.0%	100.0%	0	0	$0.00
CS Energy	Wivenhoe	W/HOE#2	Hydro	Hydro	250	0	1.0%	100.0%	0	0	$0.00
Ergon	Barcaldine	BARCALDN	Gas turbine	Natural gas	55	27	3.0%	40.0%	0.0513	0.0054	$2.43
ERM	Braemar 2	BRAEMAR5	Gas turbine	Natural gas	153	150	1.5%	30.0%	0.0513	0.0054	$8.03
ERM	Braemar 2	BRAEMAR6	Gas turbine	Natural gas	153	0	1.5%	30.0%	0.0513	0.0054	$8.03
ERM	Braemar 2	BRAEMAR7	Gas turbine	Natural gas	153	0	1.5%	30.0%	0.0513	0.0054	$8.03
InterGen	Callide C	CPP_4	Steam turbine	Black coal	405	200	4.8%	36.5%	0.095	0.002	$1.22
InterGen	Millmerran	MPP_1	Steam turbine	Black coal	425.5	130	4.7%	36.9%	0.092	0.002	$2.88
InterGen	Millmerran	MPP_2	Steam turbine	Black coal	425.5	130	4.7%	36.9%	0.092	0.002	$2.88
Origin	Darling Downs	DDPS1	Gas turbine combined cycle	Natural gas	630	270	6.0%	46.0%	0.0513	0.002	$1.07
Origin	Mt Stuart	MSTUART1	Gas turbine	Liquid Fuel	146	0	3.0%	30.0%	0.0697	0.0053	$9.16
Origin	Mt Stuart	MSTUART2	Gas turbine	Liquid Fuel	146	0	3.0%	30.0%	0.0697	0.0053	$9.16
Origin	Mt Stuart	MSTUART3	Gas turbine	Liquid Fuel	126	0	3.0%	30.0%	0.0697	0.0053	$9.16
Origin	Roma	ROMA_7	Gas turbine	Natural gas	40	0	3.0%	30.0%	0.0513	0.0054	$9.74
Origin	Roma	ROMA_8	Gas turbine	Natural gas	40	0	3.0%	30.0%	0.0513	0.0054	$9.74
QGC	Condamine	CPSA	Gas turbine combined cycle	Natural gas	140	0	3.0%	48.0%	0.0513	0.002	$1.07

Portfolio	Generator	DUID	Gen Type	Fuel	Capacity (MW)	Min Gen (MW)	Auxiliaries (%)	Thermal efficiency HHV (%) sent-out	Combustion emission factor (kg CO2-e/GJ of fuel)	Fugitive emission factor (kg CO2-e/GJ of fuel)	VOM ($/MWh sent-out, 2012 $)
Rio Tinto	Yarwun	YARWUN_1	Gas turbine	Natural gas	168	143	2.0%	34.0%	0.0513	0.0054	$0.00
Stanwell - Tarong	Barron Gorge	BARRON-1	Hydro	Hydro	30	15	1.0%	100.0%	0	0	$11.56
Stanwell - Tarong	Barron Gorge	BARRON-2	Hydro	Hydro	30	15	1.0%	100.0%	0	0	$11.56
Stanwell - Tarong	Kareeya	KAREEYA1	Hydro	Hydro	21	8	1.0%	100.0%	0	0	$6.30
Stanwell - Tarong	Kareeya	KAREEYA2	Hydro	Hydro	21	8	1.0%	100.0%	0	0	$6.30
Stanwell - Tarong	Kareeya	KAREEYA3	Hydro	Hydro	18	8	1.0%	100.0%	0	0	$6.30
Stanwell - Tarong	Kareeya	KAREEYA4	Hydro	Hydro	21	8	1.0%	100.0%	0	0	$6.30
Stanwell - Tarong	Mackay GT	MACKAYGT	Gas turbine	Fuel oil	34	0	3.0%	28.0%	0.0697	0.0053	$9.16
Stanwell - Tarong	Stanwell	STAN-1	Steam turbine	Black coal	360	190	7.0%	36.4%	0.0904	0.002	$3.26
Stanwell - Tarong	Stanwell	STAN-2	Steam turbine	Black coal	360	190	7.0%	36.4%	0.0904	0.002	$3.26
Stanwell - Tarong	Stanwell	STAN-3	Steam turbine	Black coal	360	190	7.0%	36.4%	0.0904	0.002	$3.26
Stanwell - Tarong	Stanwell	STAN-4	Steam turbine	Black coal	360	190	7.0%	36.4%	0.0904	0.002	$3.26
Stanwell - Tarong	Swanbank E	SWAN_E	Gas turbine combined cycle	Coal seam methane	385	150	3.0%	47.0%	0.0513	0.0054	$1.07
Stanwell - Tarong	Tarong	TARONG#1	Steam turbine	Black coal	350	140	8.0%	36.2%	0.0921	0.002	$7.61
Stanwell - Tarong	Tarong	TARONG#2	Steam turbine	Black coal	350	140	8.0%	36.2%	0.0921	0.002	$7.61
Stanwell - Tarong	Tarong	TARONG#3	Steam turbine	Black coal	350	140	8.0%	36.2%	0.0921	0.002	$7.61
Stanwell - Tarong	Tarong	TARONG#4	Steam turbine	Black coal	350	140	8.0%	36.2%	0.0921	0.002	$7.61
Stanwell - Tarong	Tarong North	TNPS1	Steam turbine	Black coal	443	175	5.0%	39.2%	0.0921	0.002	$1.46

Data source: ACIL Tasman *PowerMark* database

Deliberately left blank