A C I L   A L L E N   C O N S U L T I N G

REPORT TO
QUEENSLAND COMPETITION AUTHORITY

21 NOVEMBER 2013

ESTIMATED ENERGY COSTS

2014-15 RETAIL TARIFFS

FOR USE BY THE QUEENSLAND COMPETITION AUTHORITY IN ITS DRAFT DETERMINATION ON RETAIL ELECTRICITYTARIFFS

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ACIL ALLEN (2013) ESTIMATED 2014-15 ENERGY COSTS FOR QCA

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1 Introduction

This report provides estimates of expected energy costs for use by the Queensland Competition Authority (the QCA) in developing retail electricity tariffs for 2014-15.

The report considers the submissions made by various parties following the QCA's Interim Consultation Paper, *Regulated Retail Electricity Prices 2014-15* (July 2013), where those submissions refer to the cost of energy in regulated retail electricity prices.

It also takes into consideration material and views presented by various parties at the technical workshop on cost of energy modelling held on 27 September 2013.

Retail prices generally 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 QCA and which is attached as Appendix B, the methodology developed by ACIL Allen provides an estimate of energy costs to be incurred by a retailer to supply customers on notified prices for 2014-15; 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.

In addition to the scope of work outlined in the TOR, the QCA has asked ACIL Allen to provide energy cost estimates for two cases assuming certainty about carbon pricing as follows:

1. the fixed carbon price continues throughout 2014-15 in its present form of \$25.40/tonne CO_2-e
2. no carbon price applies in 2014-15 – assumes that the Clean Energy Act (CEA) is repealed.

1.1 Background

ACIL Allen notes that in accordance with the Delegation and TOR, its task is to provide expert advice to the QCA on the energy costs to be incurred by a retailer to supply customers on notified prices for 2014-15 taking into account the uncertainty over the carbon price and any other uncertainties.

For the two additional cases requested by the QCA, ACIL Allen is to provide its best estimate of energy costs for a case with a carbon price (Carbon case) and a case without a carbon price (No carbon case). In these two cases the status of the carbon price is assumed to be known; that is, it is assumed there is no uncertainty with respect to the future of the carbon price in each case (it is known to continue or it is known to be repealed).

1.1.1 ACIL Allen's best estimate of wholesale energy costs

In preparing the advice on the estimate as outlined in the TOR, ACIL Allen is 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 2014 to 30 June 2015.

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 (WEC) component.

In the interest of clarity, in undertaking the task, ACIL Allen 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 Allen understands that these matters will be considered by the QCA 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 Allen has taken a consistent approach with advice it provided to the QCA 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.

1.1.2 Estimation of WEC – with and without carbon

In estimating energy costs for the two additional cases (Carbon and No carbon), ACIL Allen has used its best endeavours to estimate the WEC for two hypothetical situations given the actual uncertainty around the proposed repeal of the CEA including the timing of any repeal. In these cases it is that the carbon price is either \$25.40/tonne CO_2-e in the Carbon case or \$0/tonne CO_2-e in the No carbon case.

In order to extrapolate from the real-world in which the future carbon price is uncertain, ACIL Allen has used broker price data for contracts that trade ex-carbon (carbon is added using an agreed methodology in the event that the CEA is not repealed) to estimate the risk adjusted allowance for carbon in futures prices. This risk adjusted carbon estimate has then been subtracted from the actual futures prices to give estimated equivalent futures prices for the No carbon case. Finally, for the Carbon case, the full carbon price of \$25.40 multiplied by the estimated emissions intensity of the NEM is added to the No carbon case futures price estimates to derive the Carbon case futures price estimates.

1.2 Methodology

1.2.1 ACIL Allen's best estimate

ACIL Allen's best estimate methodology is consistent with the methodology used to provide advice to the QCA for the 2013-14 Final Determination.

The approach adopted by ACIL Allen 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 then added to the wholesale energy costs and the total is then adjusted for assumed network losses.

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 Allen's ongoing development of the underlying methodology and modelling capability. In particular, for 2014-15, refinements have been necessary to account for the new LNG load and for the carbon price uncertainty.

Projected strong growth in the Queensland demand throughout 2014-15 due to the ramp up in operation of the LNG projects needs to be properly accounted in the simulation of the wholesale electricity market (or pool). ACIL Allen's demand projection methodology relies on weather matching recent actual demands to create 43 underlying simulated hourly demand sets which are then grown to a set of parameters for 2014-15. However, unlike recent history, for which demand across the year has displayed very weak growth, the relatively 'steep' ramp up in demand associated with the commissioning of the LNG projects needs to be properly accounted so as not to distort the grown demand sets. This has been achieved by deducting the growth due to the LNG projects from the 2014-15 annual energy and peak demand forecasts (i.e. the effect of LNG has been removed from AEMO's 2014-15 annual energy and peak demand forecasts). The 43 demand sets are then grown to these adjusted parameters and the assumed demand profile associated with the LNG projects (which can be thought of as a 'wedge' of demand increasing in quantity from July 2014 to June 2015) is added to each of the 43 grown demand sets.

This staged approach in developing the 43 demands sets for Queensland for 2014-15 is also useful for developing the 43 simulated demand sets for the NSLPs . Specifically, the 43 simulated demand sets for the NSLPs are derived from the 43 simulated demand sets for Queensland demand prior to the addition of the LNG associated demand. This means the NSLP demand sets quite appropriately do not display the same degree of intra-year growth as the Queensland demand for 2014-15.

As in the past, the inferred risk adjusted carbon price[1] has been used in the analysis for 2014-15. However, unlike the analysis for 2013-14 where a full carbon price allowance was applied as there was no risk that the carbon price would be repealed, uncertainty over the

[1] The risk adjusted carbon price for 2014-15 is the carbon price ($25.40/tCO2-e under the CEA) multiplied by the probability of the carbon price remaining in effect in 2014-15. This is also referred to as the carbon price allowance or carbon allowance throughout this report.

carbon price for 2014-15 has lead to a significant lowering in the contract market's allowance for the carbon price.

1.2.2 Cases with and without a carbon price

A very similar methodology is used for the two carbon price cases[2] except that the ASX Energy futures contract prices are adjusted to incorporate the full carbon price (adjusted for the average emissions intensity of the NEM) for the with Carbon case and a zero carbon price for the No carbon price case.

There is insufficient trading in quarterly over the counter (OTC) contracts to provide a sound estimate of the quarterly contract prices exclusive of the carbon price. However, there is sufficient OTC data to estimate the risk adjusted carbon price on a half yearly basis by subtracting the average daily OTC contract price exclusive of carbon from the average daily OTC contract price inclusive of carbon. Daily OTC contract price data covering the latter half of 2014 and the whole of 2014-15 are used in this analysis. We have estimated the quarterly contract prices exclusive of carbon by subtracting estimated half-yearly risk adjusted carbon price from the quarterly ASX Energy futures prices (noting that the AFX Energy prices are carbon inclusive).

1.2.3 Pool modelling

The pool price modelling involves developing 43 hourly demand sets and 11 plant outage profiles for 473 simulations of 2014-15, and estimating hourly pool prices using ACIL Allen's National Electricity Market (NEM) simulator, *PowerMark.* These are used in conjunction with the retailer contracting model to estimate the WEC.

1.2.4 Electricity hedging

The retailer contracting model simplifies 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 473 simulations of 2014-15 to estimate the WEC.

1.2.5 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)
- NEM management fees
- Ancillary services
- Prudential costs.

[2] These are the two additional cases requested by the QCA, one with full carbon price and the other with no carbon price.

The Queensland Gas Scheme is to be discontinued in 1 January 2014 so is not included in the 2014-15 energy cost estimates.

2 Stakeholder submissions

2.1 Introduction

This section responds to a variety of comments and proposals made in submissions by stakeholders in response to the QCA's Interim Consultation Paper, *Regulated Retail Electricity Prices 2014-15: (July* 2013*)* and presentations at the technical workshop on cost of energy modelling held on 27 September 2013. Submissions and presentations raised a number of queries and made a number of suggestions for changes to the methodology used in estimating energy costs.

2.1.1 General themes in submissions

There were some consistent themes in the retailer submissions:

The first theme is that retailers are concerned that regulated retail prices are not set at too low a level such that they stifle competition. In order to avoid this possibility and to ensure adequate ongoing investment in generation retailers generally still favour the long run marginal cost (LRMC) of generation as a floor to the regulated price.

The second theme is that a wider range of hedging instruments should be used in estimating the WEC. The arguments in favour of a wider range of instruments are generally based on concerns that basing the WEC estimates on one type of market hedging instrument does not fully capture the actual cost of energy borne by retailers. It is argued that other forms of hedging including power purchase agreements (PPAs) and retailer owned generation are legitimate hedging instruments and their actual costs should also be included.

The third theme in retailers' submissions and presentations is that there is a need to address the carbon price uncertainty in 2014-15. To address this uncertainty some retailers suggest that pool and contract prices both inclusive of the full carbon price and exclusive of the carbon price be developed and then be applied to the 2014-15 retail tariffs so as to incorporate the actual carbon price applying at the time. Other retailers have suggested that some level of carbon costs should be recognised even where the CEA is repealed reflecting the cost of uncertainty in hedging prior to its repeal.

It is suggested by some retailers that the OTC contract prices which exclude the carbon price could be used for the No carbon case and the pass through of carbon price be added to arrive at the retail prices with the carbon price.

A fourth theme relates to retailer's concerns about apparent lack of load variability in the methodology as applied. Retailers have expressed particular concerns about the use of the 10 per cent probability of exceedence (10% POE) peak demand parameters from the 2013 AEMO National Electricity Forecasting Report (NEFR) to construct the 43 simulated demand sets used in the modelling and WEC estimates (Queensland and Energex NSLP).

Additionally, retailers have criticised, in their view, the inability of the methodology to incorporate the effects of successive hot days on peak demand. It is argued that the number of high demand events associated with extreme weather is underrepresented. The main thrust of this criticism is that, in their view, extreme demands are underrepresented and thereby modelled spot prices are lower than they should be and hedging risks are not properly represented.

The fifth theme is a view that the approach lacks transparency and that the release of load and pricing data is too limited. This, it is argued, makes it difficult for stakeholders to fully comprehend the information and modelling results and provide well based comments and feedback on the process and results.

2.1.2 ACIL Allen's summary response

Following a further careful consideration of the various criticisms and suggestions provided in the submissions, ACIL Allen has not been persuaded to change the method for estimating hedging costs that was used for the 2013-14 Final Determination. Apart from the suggestions regarding treatment of carbon price uncertainty in 2014-15 no compelling new material or suggestions have been presented in the submissions and presentations.

While we accept there is carbon price risk in 2014-15 with its repeal still uncertain, it is generally understood that this uncertainty is reflected in ASX Energy futures prices which in effect, includes the market's view on the probability of the carbon price remaining in place in 2014-15, and thereby incorporates a risk adjusted carbon price allowance. The data presented by both Origin and Energy Australia show the carbon allowance in futures prices for 2014-15 period currently appears to be noticeably lower than would be expected if there was 100% certainty that the carbon price was to remain in effect in 2014-15. As 2014-15 approaches and assuming the fate of the carbon price becomes clearer, then ASX Energy futures prices, all other things equal, should move up or down accordingly. This price movement should be reflected in the hedge price estimates for the 2014-15 Final Determination, at least until the cut-off point for the Final Determination which is driven by the need to gazette the 2014-15 tariffs by a predetermined time.

The QCA has requested ACIL Allen to provide it with two additional energy cost estimates, one for the No carbon case (with 100% certainty) and the other for the Carbon case (with 100% certainty). These two cases effectively assume perfect knowledge of the future with the first assuming it is repealed for the whole year and the other assuming that it is not repealed.

In providing these estimates ACIL Allen notes that regulated retail prices based on energy cost estimates with and without carbon will result in an increased risk of under-estimating retailer energy costs if the carbon price is repealed and over-estimating retailer energy costs if the carbon price is not repealed. This is because current pricing is trading on a risk adjusted basis and retailers are likely incurring actual costs at these risk adjusted prices regardless of whether the carbon price is repealed or not. On this basis, ACIL Allen recommends that the QCA use ACIL Allen's best estimate based on the risk adjusted carbon price allowance.

2.2 LRMC as a price floor

All retailer submissions continued to call for the LRMC of generation to be used as a floor to the WEC. ACIL Allen considers that LRMC is a poor proxy for the actual costs faced by a retailer in supplying non-market customers in Queensland with electricity retail services in 2014-15.

ACIL Allen 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 2014-15, except as a matter of coincidence.

2.3 Inclusion of PPAs

A number of retailer submissions have proposed changes (as in previous years) to the methodology to take account of actual prices paid for long dated power purchase agreements (PPA). The latest submissions do not contain any additional information to support the inclusion of the prices of these instruments in the methodology and as such ACIL Allen has made no changes to its methodology.

In our report, dated May 2013 associated with the QCA's Final Determination for 2013-14 [3], ACIL Allen (then ACIL Tasman) recognised that retailers enter into a variety of hedging arrangements including PPA and physical generation options. The usefulness of considering generation options as hedging costs was considered in some detail with the conclusion being that using the face-value costs of these instruments had little merit. This is because generation investments are typically long dated and may have been committed some time ago. The nominal price in a PPA or the annualised historical cost of generation would reflect the value of the generation anticipated at the time of commitment, when the investor was faced with a variety of uncertain futures. Once an investment is committed, the costs are sunk. As time proceeds, the value of the generation asset is determined by the actual future that eventuates and may be quite different to the value expected at the time of commitment.

We also stated in the report that there are also usually additional benefits to a retailer owning a PPA or physical generation beyond any hedge benefits. These are likely to include some or all of the following:

— the right to dispatch the associated plant (the ability to vary the volume and price at which it is offered and by implication the ability to have some influence on the market price outcome including benefiting from price rises)

[3] Estimated energy costs for 2013-14 retail tariffs - Estimated energy costs for use by the Queensland Competition Authority in its Final Determination on retail electricity tariffs for 2013-14 (May 2013) - published on the QCA website

- the ability to profit from market price rises when there are substantial rises in new entrant capital costs (PPA costs are typically linked to the associated plant's sunk capital costs with or without indexing usually in some way linked to inflation) – as an example capital costs rose between 50% and 100% between 2004 and 2008 as commodity prices and labour costs rose significantly
- the ability to profit when rises in alternative fossil fuel costs occur – i.e. a gas fired plant benefits when rises in coal prices occur driving up electricity prices in the future and similarly a coal fired plant benefits when rises in gas prices occur
- in the case of gas fired plant which has much lower carbon intensities than coal fired plant, benefiting when carbon prices are introduced or rise as NEM price rises linked to carbon are expected to be dominated by coal fired plant over that period
- the bringing forward of the monetisation of own fuel resources that otherwise may have taken many years to market and sell.

As a consequence, ACIL Allen considers that the likelihood of these historical costs reasonably representing the actual costs of supplying customer retail services to the premises of non-market customers would be largely a matter of coincidence.

2.4 Addressing carbon price uncertainty

In order to address the carbon price uncertainty inherent in the current market retailers generally suggested that pool and contract prices be developed both with carbon and without carbon and then applied so as to incorporate the actual carbon price applying in 2014-15. It was suggested by some that the OTC contract prices, which trade without carbon, could be used for the No carbon case and then carbon added (at the estimated NEM emissions intensity) to calculate contract prices for the Carbon case.

We accept that there is carbon price risk in 2014-15 as the repeal of the CEA and its timing remains uncertain. However, this uncertainty is reflected in ASX Energy futures prices as they are a standardised product with no settlement adjustments regardless of the status of the carbon price; i.e. the seller and buyer take on the risk of changes in the carbon price. Subtracting the OTC prices trading without carbon from the futures prices in effect provides the risk adjusted market price allowance for carbon[4].

Both Origin Energy and Energy Australia provided data that demonstrates that the market price allowance for carbon in futures prices for the 2014-15 period currently appears to be noticeably lower than would be expected if there was 100% certainty that the carbon price was to remain in effect in 2014-15. As 2014-15 approaches and assuming the fate of the carbon price becomes clearer, then all things equal, ASX Energy futures prices will likely move up or down accordingly. This price movement will be reflected in the hedge price estimates for the 2014-15 Final Determination.

As mentioned in Section 2.1.2 QCA has requested ACIL Allen to provide it with two additional energy cost estimates, one with no carbon price (with 100% certainty)and the

[4] This assumes that liquidity in both the OTC and futures markets is at an acceptable level such that any arbitrage between the two products is minimal.

other with the carbon price (with 100% certainty). These two cases effectively assume no uncertainty over the carbon price with one assuming it is repealed for the whole year and the other assuming that it is not repealed.

Again as mentioned in Section 2.1.2 ACIL Allen notes that regulated retail prices using the energy cost estimates with and without carbon will result in an increased risk of retailers under-recovering energy costs if the carbon price is repealed and over-recovering energy costs if the carbon price is not repealed. On this basis ACIL Allen recommends to the QCA that for the retail tariffs for 2014-15 the energy cost estimate using a risk adjusted market price allowance for carbon be applied. Under this approach regulated tariffs need not change should the carbon price be repealed for all or part of 2014-15 as such an outcome is already factored into the estimate of the energy cost component.

However, ACIL Allen notes that there may be competition considerations for the QCA in the event that the carbon price is not repealed. In such circumstances a new entrant retailer in 2014-15, may face the full cost of carbon when seeking to acquire hedges to enter the market. These are matters for the QCA to consider and are outside the TOR.

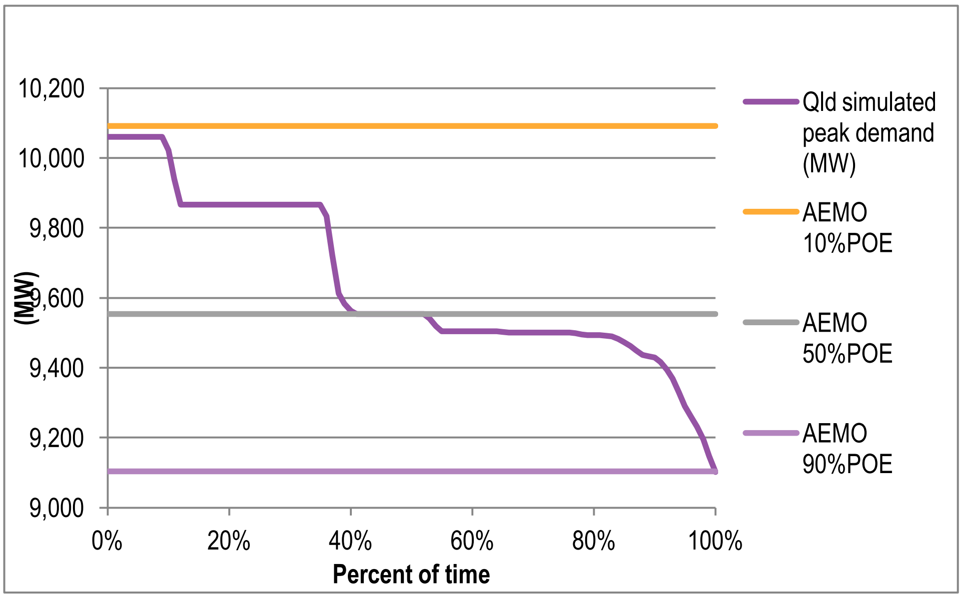
2.5 Coverage of extreme demand events

Some submissions expressed concern that the ACIL Allen methodology for estimating WEC results is an under representation of extreme demand events. Given that the ACIL Allen methodology uses the AEMO peak demand forecast as its basis, we are satisfied that extreme demand events are represented for the Queensland demand sets. This is explained in some detail below.

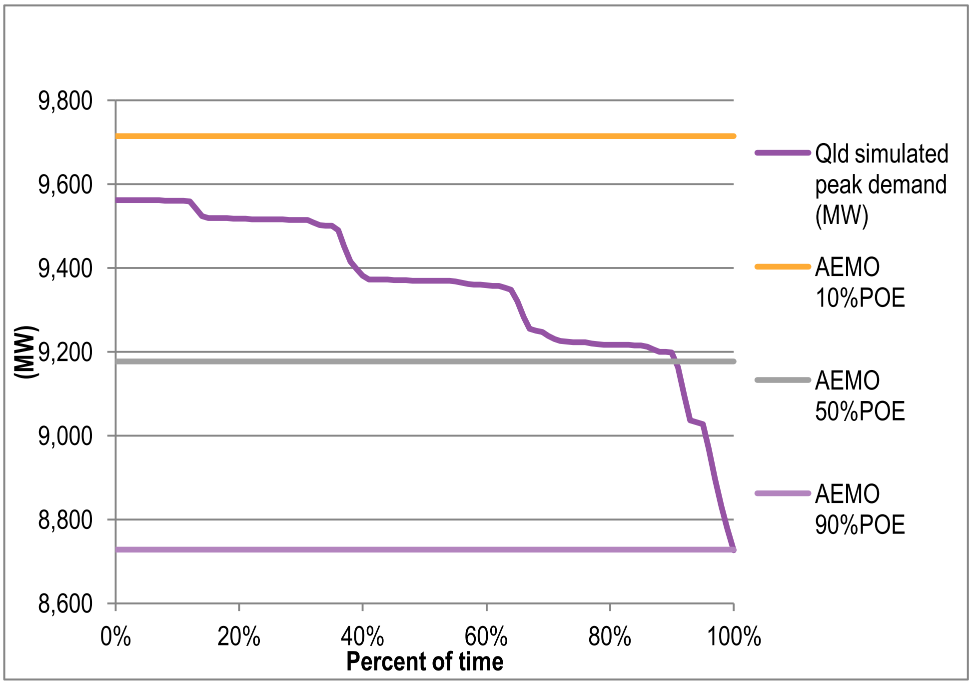
Figure 1 shows the distribution of 2014-15 annual peak demands for Queensland from the 43 simulated demand sets. The upper graph shows the peak demands prior to deducting the contribution of rooftop solar PV and the lower graph shows the distribution after accounting for solar. The upper graph shows the methodology results in a distribution of annual peak demands that matches the AEMO demand forecast parameters. However, as discussed in the 2013-14 Final Determination report, ACIL Allen's approach to deducting solar is different from AEMO. AEMO assumes a constant reduction in peak demand based on solar output at 4pm. In the ACIL Allen approach the peak demand varies depending on temperature conditions and as a consequence the deduction of solar depends on the timing of the peak demand in each of the 43 simulated demand sets.

Figure 1 **Queensland simulated annual peak demand – 2014-15**

Prior to solar output being deducted



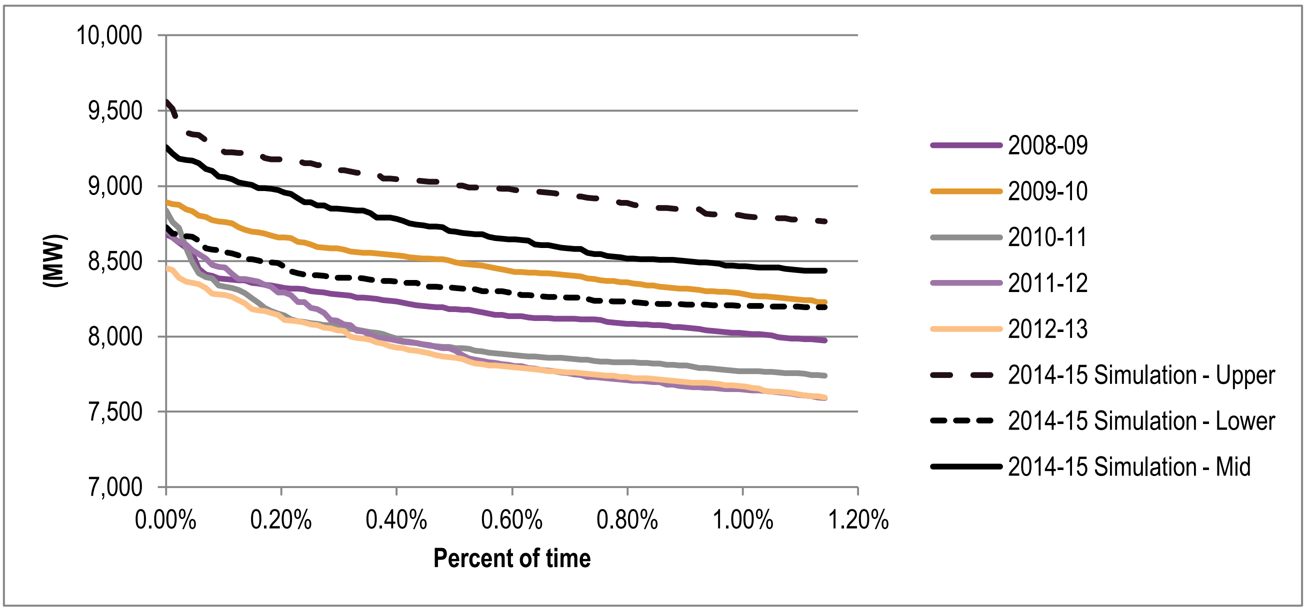
After solar output is deducted



Source: ACIL Allen analysis and AEMO data

Figure 2 shows the upper 100 hour segment of the demand duration curves for three of the 43 simulated Queensland demand sets resulting from the methodology. The three demand sets in the graph represent the upper, lower and middle of the range of demand duration curves across all 43 simulated sets. Included for reference are the demand duration curves for the actual demands for 2008-09 to 2012-13. It can be seen that the demand duration curves of the simulated demand sets for 2014-15 not only envelope the recent historic demand duration curves, but demonstrate that the difference between the maximum and minimum of the envelope averages around 700MW across the top 100 hours - that is, the variation between the simulated demand sets does not just occur at the single peak annual demand but across a reasonable portion of the demands within the given simulation. This variation in demand contributes to the variation in modelled pool price outcomes discussed in Section 2.6.

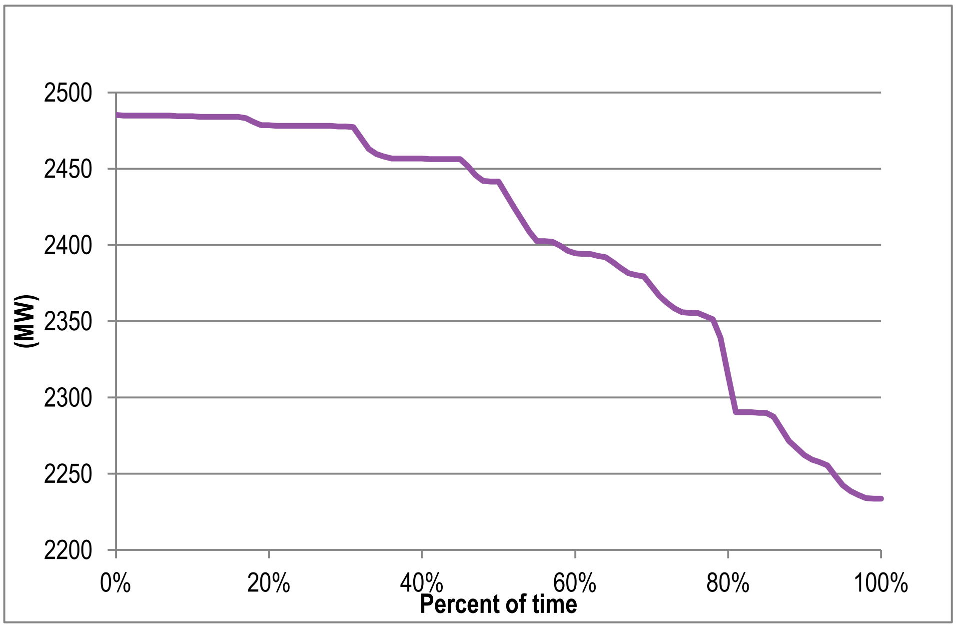
Figure 2 **Top 100 hourly demands – Queensland**



Note: Data for 2008-09 to 2012-13 includes top 200 half hourly demands.
Source: ACIL Allen analysis and AEMO data

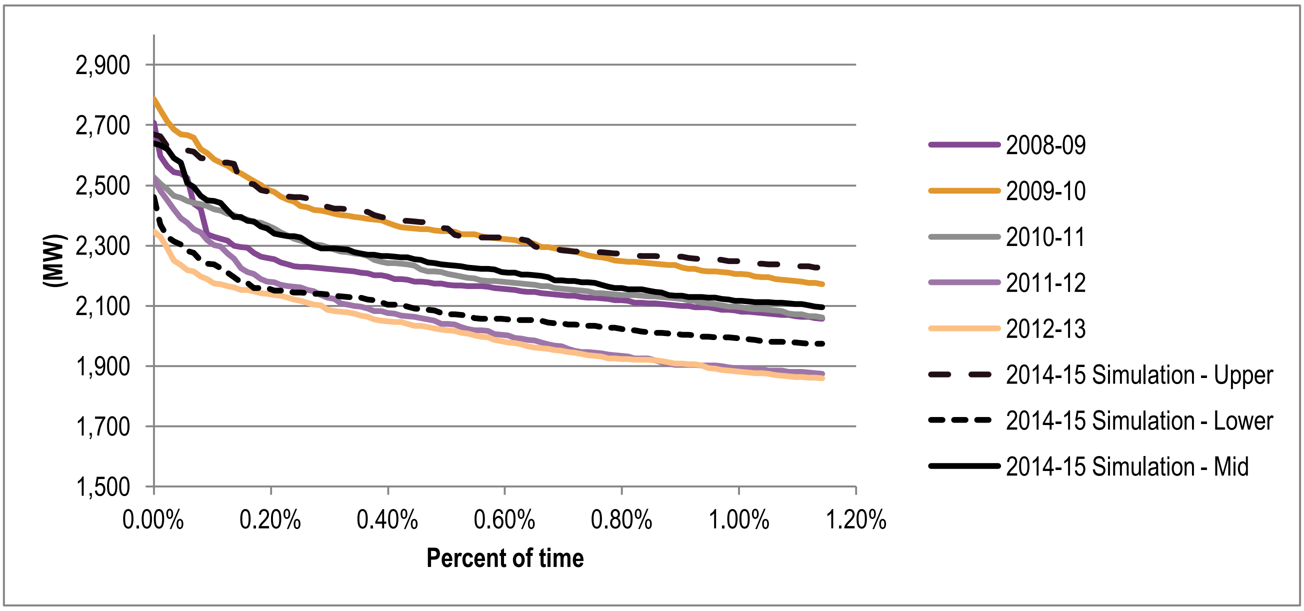
Figure 3 shows the resulting distribution of annual peak demands for the Energex NSLP for 2014-15 from the 43 simulated demand sets. Figure 4 shows the variation in the simulated Energex NSLP demand sets envelopes recent outcomes and covers an average range of about 250MW across the top 100 hours. Although there is a degree flatness in the upper 10% of the distribution of simulated annual peak demands for the NSLP, within a given simulated year this is not the case with the annual load factor ranging between 38.4% and 43.2% compared with a range of 39.6% to 43.3% for the actual NSLP between 2008-09 and 2012-13. Nonetheless, ACIL Allen recognises the flatness in the top 10% of the simulated annual peak demands would be of concern to the retailers and this issue is addressed later in this report.

Figure 3 **Energex NSLP simulated annual peak demand – 2014-15**



Note: Demands are presented after the solar PV contribution has been deducted
Source: ACIL Allen analysis and AEMO data

Figure 4 **Top 100 hourly demands – Energex NSLP**



Note: Data for 2008-09 to 2012-13 includes top 200 half hourly demands.
Source: ACIL Allen analysis and AEMO data

2.5.1 Consecutive hot days

The methodology for developing the demand traces incorporates the last 43 years of temperature data to establish 43 annual demand traces. Although there may not be consecutive hot days in the four base years of temperature and demand data (2009-10 to 2012-13), the 43 simulated demand sets are scaled to the AEMO demand forecast parameters. The process adopted by AEMO in estimating the demand parameters takes into account temperatures over consecutive days.

2.5.2 Use of latest four years of demands

Submissions suggest that given the weather and demand in the four base years (2009-10 to 2012-13 for the 2014-15 tariff calculations) used to construct the 43 simulated demand sets are subdued, the resulting simulated profiles do not incorporate sufficient variation and under represent high demands. Such comments appear to misunderstand the methodology for constructing the simulated demand sets.

The methodology scales the simulated demand sets to the AEMO demand forecast parameters, including the 10%POE peak demand. Figure 2 and Figure 4 in Section 2.5 show quite clearly that there is reasonable variation in simulated demand outcomes for Queensland and the Energex NSLP. Further, the graphs in Section 2.6 show the adoption of the simulated demand sets in the pool modelling results in a reasonable spread in pool price outcomes.

2.5.3 Overall peak of the simulated load traces for 2014-15 should exceed the AEMO 10%POE peak demand

Submissions suggest the overall peak demand for Queensland across the 43 simulated demand sets should exceed the AEMO 10% POE demand forecast which is a 1 in 10 year peak demand not a 1 in 43 year peak.

In a supplementary submission AGL has made suggestions involving use of regression analysis to develop relationships between load and temperature and applying these to the temperature data to arrive at peak demands. In ACIL Allen's experience the AGL approach is not without its challenges and is very likely to have no noticeable impact on the final result. The weather diversity across Queensland dampens the effect of the relationship between temperature and demand. A number of projects undertaken by ACIL Allen on this aspect for many clients including Ergon Energy, Energex and Powerlink have revealed that peak demand is not a linear function of temperature and that above certain temperatures, the relationship between temperature and peak demand weakens such that peak demand tends to reach a limit or a point of saturation

ACIL Allen acknowledges that there are limitations in its methodology. However, based on tests against the NSLP, such as adding 300 MW to the upper one percent of hourly demands in the top 10% of demand sets shows no noticeable impact on the final result and as a consequence ACIL Allen is not convinced of the need to revise its methodology. On arriving at this position we were guided by whether changing this aspect of the methodology would make a difference to the projected pool price outcomes or the NSLP annual load weighted and hedged prices.

We also note that any increase in demand beyond the 10%POE level would need to be estimated and is likely to be just as contentious. ACIL Allen has analysed the relationship between temperature outcomes and demand and found a softening of the demand response to an increase in temperature when temperature exceeds 35 degrees. Put simply, at 35 degrees the majority of air conditioning demand is likely to be activated and beyond 35 degrees variations in demand levels appear largely to be function of the timing of the cycling of air conditioning demand and regional variations in temperature within the state.

2.5.4 Greater weighting should be given to Brisbane and Sydney temperatures in selection of days.

As in previous years, some retailers suggest that greater weight be given to the Sydney and Brisbane temperature profiles when undertaking the matching process to develop the weather influenced demand sets. The basis of the suggestion seems centred on the concern that the temperatures of the southern states may themselves be closely correlated, but only loosely correlated with Brisbane, thereby biasing the matching process and resulting in unreasonably high or low demands in Queensland (and hence prices).

ACIL Allen's response remains that we are modelling the entire NEM not just the Queensland and NSW regions of the NEM in isolation. Rather than introducing bias, the matching process minimises bias and it is therefore important to retain our standard approach. In any case, any residual bias largely offset by the underlying demand forecast parameters to which the demands are scaled in each region.

2.6 Demand and price simulation results

In the interests of providing greater transparency for stakeholders, we have provided a number of general observations of the results derived by applying the ACIL Allen methodology. These results demonstrate that there is a wide range of simulated pool price outcomes which we are satisfied covers the expected range of outcomes over the period 2014-15.

In addition to the pool price simulation results, the effect of hedging on the WEC is also considered. The hedge strategy employed ensures that in most periods, the NSLP demand is fully covered by hedges. In general, higher pool prices, all other things being equal, are linked to periods of higher Queensland demand. Therefore, in hedging the NSLP, the correlation between the Queensland and NSLP demand traces is a critical factor. The maximum NSLP demand generally occurs outside the periods of extreme simulated Queensland demand/price. Given the lack of correlation between the projected extreme prices in Queensland and the NSLP peak demand, the absolute estimate of the NSLP peak demand has little effect on the WEC estimate.

These matters are covered in some detail in the following sub-sections.

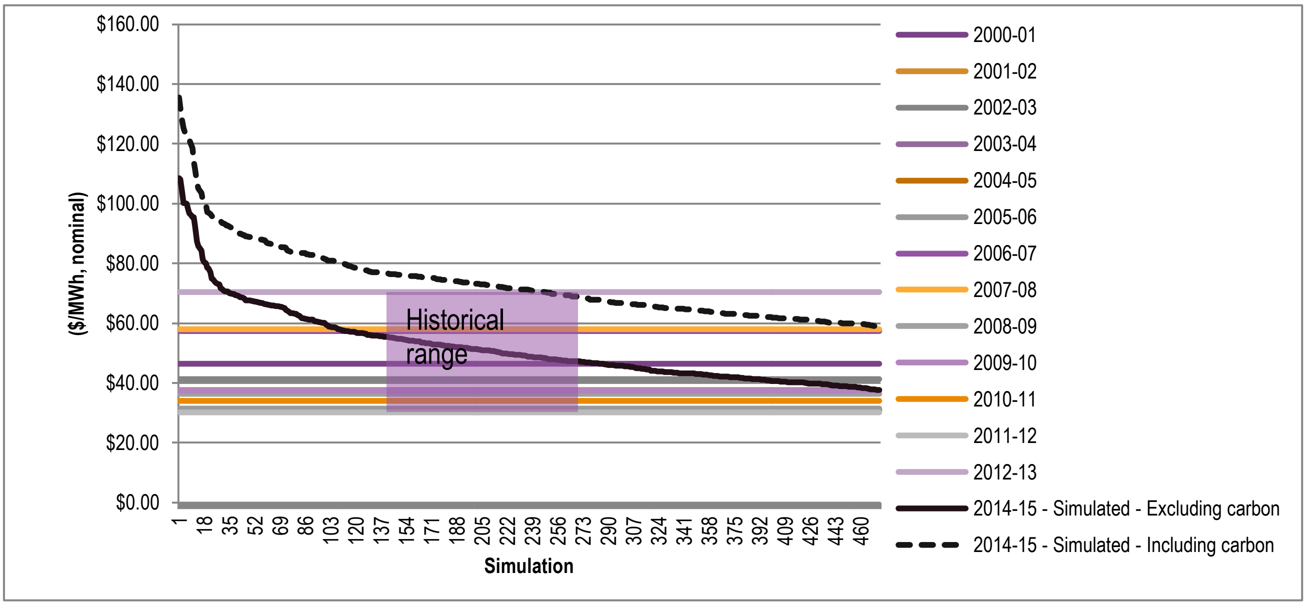
2.6.1 Queensland pool prices

Two sets of pool price simulations were run in *PowerMark* - one assuming the carbon price is repealed and the other assuming the carbon price remains in place in 2014-15. In the simulations which assume the carbon price remains in place, we adopt the full carbon price of \$25.40/tonne CO_2-e in the model inputs (which is then added to the short run marginal cost of each generator as a function of the generator emissions intensity), not the risk adjusted carbon price. The configuration of *PowerMark* is based on ACIL Allen's latest internal simulation of the NEM - no adjustments to our standard assumptions have been made for this engagement.

The annual demand weighted pool prices (DWP) for Queensland from the 473 simulations range from a low of $37.55/MWh to a high of $108.61/MWh when excluding carbon and $58.79 to $135.61/MWh when including carbon. This compares with the lowest recorded Queensland DWP in the last 13 years of $30.06/MWh in 2011-12 to the highest during the drought year of 2007-08 of $58.07/MWh; in 2012-13 the inclusion of the carbon price increased outcomes to $70.34/MWh (but this would be less than the price during the drought if there was no carbon price in 2012-13).

Figure 5 compares the Queensland DWP for the 473 simulations for 2014-15 with the Queensland DWPs from the past 13 years. Although there have been changes to both the supply and demand side of the market, it clearly shows that the simulations cover a noticeably wider range in potential prices for 2014-15 than has occurred in the past 13 years of history. The top 34 of the simulations excluding carbon (7.2% of all simulations) exceed the highest DWP yet recorded - keeping in mind the annual DWP of 2007-08 was partly the result of the millennium drought conditions and the 2012-13 DWP includes an uplift due to the carbon price ($23.00/tonne CO_2-e). ACIL Allen is satisfied that in an aggregate sense the distribution of the 473 simulations for 2014-15 cover an adequately wide range of possible annual pool price outcomes for 2014-15.

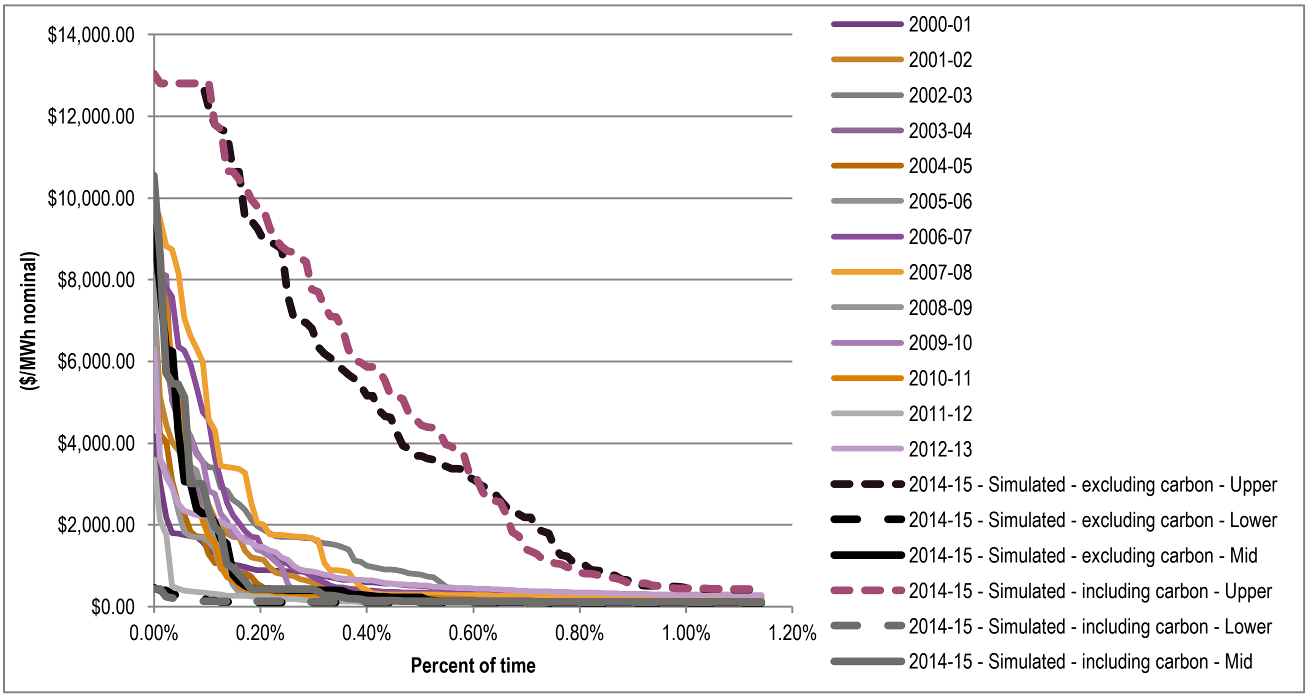
Figure 5 **Annual DWP for Queensland for 473 simulations for 2014-15 compared with actual outcomes in past years**



Source: AEMO historic pool price data and ACIL Allen results from PowerMark modelling

Comparing the upper 1% of hourly prices in the simulations with historical spot prices shows the spread of the prices from the simulations also more than adequately covers the historical spread of spot prices. The comparison is illustrated in Figure 6 which clearly demonstrates that range of upper 1% of prices from the 473 simulations for 2014-15 easily encompasses the range of historical prices. It is also notable, that as would be expected, the distribution of simulated price outcomes demonstrates a strong positive skewness.

Figure 6 **Comparison of upper tail of hourly price duration curve for Queensland for 473 simulations for 2014-15 compared with actual outcomes in past years**



Source: AEMO historic pool price data and ACIL Allen results from PowerMark modelling

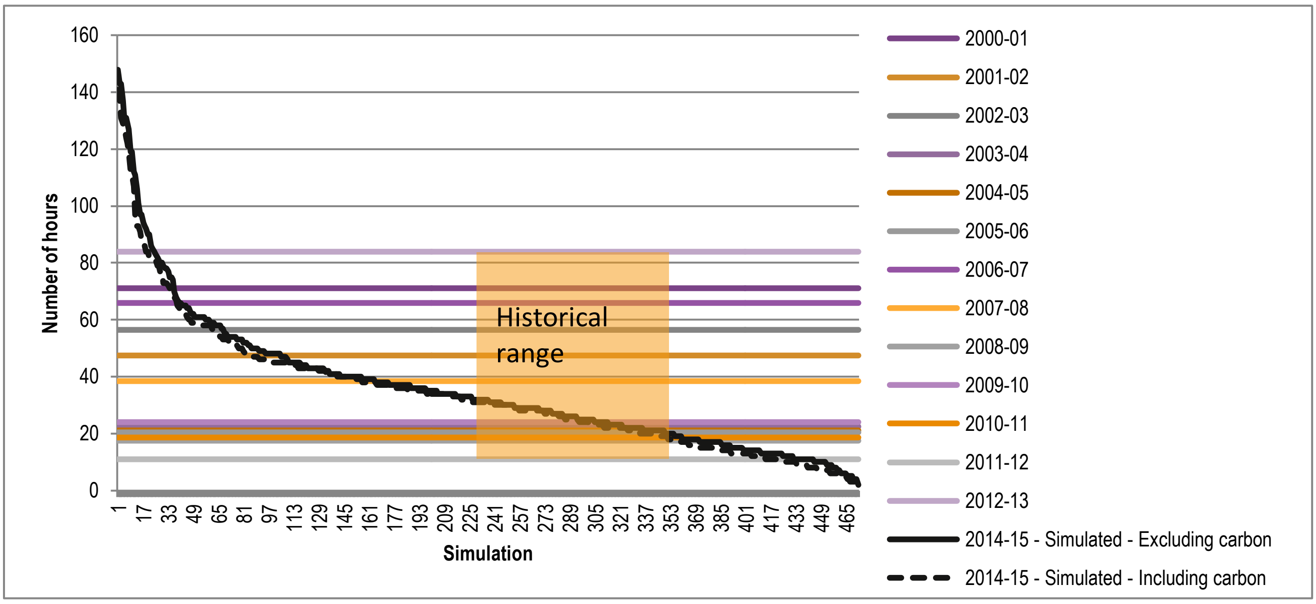
ACIL Allen is satisfied the Queensland pool prices from the 473 simulations cover the range of expected price outcomes for 2014-15 both on average and in the upper tail. These comparisons clearly show that the 43 simulated demand traces combined with the 11 plant outage scenarios provide a sound basis for modelling the expected future outcomes for 2014-15.

2.6.2 Prices over $300/MWh

ACIL Allen is also satisfied that *PowerMark* has performed adequately in capturing the extent and level of the high price events based on the demand and outage inputs for the 473 simulations. Figure 7 shows that the number of hours when the price is above $300/MWh captured in the modelling of the 473 simulations compares favourably with history. Furthermore, the range in annual average contribution to the time weighted price (TWP), of prices above $300/MWh, for the 473 simulations is consistent with those recorded in history as shown in Figure 8. It is worth noting, that the inclusion of the carbon price in

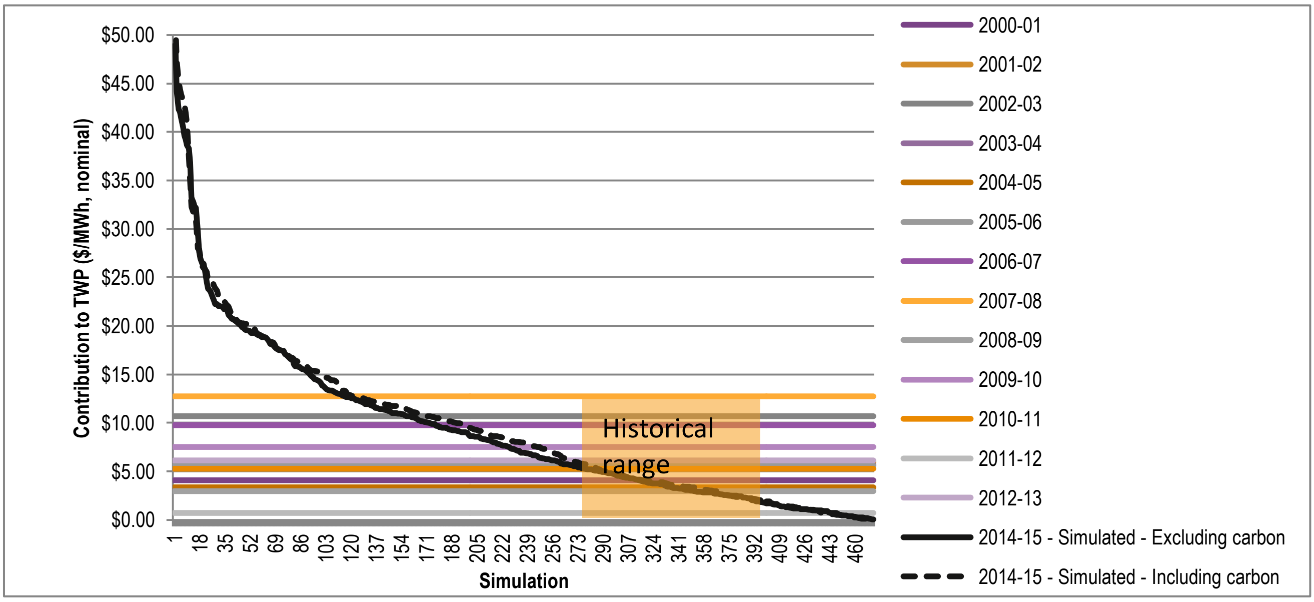
2014-15 does not alter noticeably the number of hours above $300 or the contribution of these high priced events to the annual average price (all other things equal). In other words, including the carbon price in 2014-15 does not on its own change the underlying price volatility in the NEM (although it may well change the nature of the NEM over time).

Figure 7 **Number of hours when prices are above $300/MWh in the modelled simulations and recorded in the past**



Source: AEMO historical pool price data and ACIL Allen results from PowerMark modelling

Figure 8 **Annual average contribution to the TWP by prices above $300/MWh in the modelled simulations and recorded in the past**



Source: AEMO historical pool price data and ACIL Allen results from PowerMark modelling

2.6.3 Energex NSLP demands

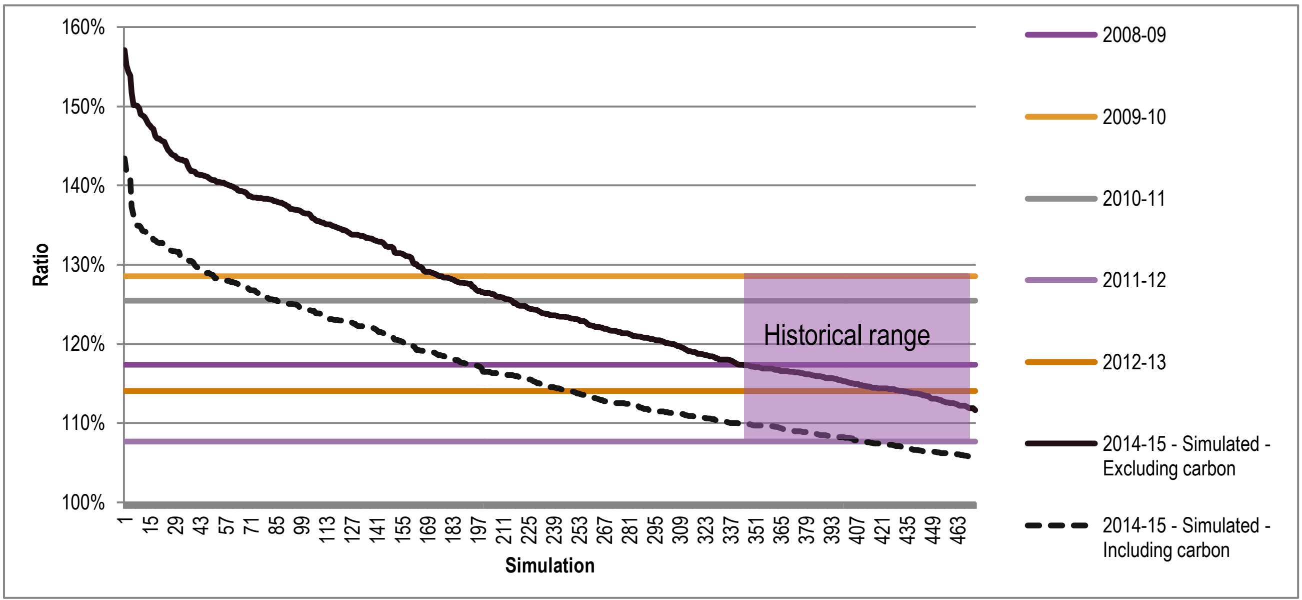
In the past there have been suggestions that the Energex NSLP peak demand is too low which in turn is presumed to lead to a lower cost to supply the NSLP. However, the maximum demand of the NSLP is not in isolation a critical feature in determining the cost of supply. As discussed at the beginning of Section 2.6 above, the shape of the NSLP demand trace and its relationship to the shape of the Queensland demand/price traces is critical factor in the cost of supplying the NSLP demand. The summer maximum demand for the NSLP occurs in the evening (typically around 7:30pm) while the Queensland summer demand peaks occur earlier in the afternoon (usually between 2pm and 4pm). This means that the peak of the NSLP is less likely to be coincident with extreme price events associated with the afternoon Queensland peak. Furthermore, using past data as a guide, the annual peak of the NSLP may occur in winter which has a different set of characteristics and relationship to price.

A test of the appropriateness of the NSLP demand shape and its relationship with the Queensland demand shape can be undertaken by comparing the annual DWP for the Energex NSLP with the Queensland TWP. Figure 9 shows that, for the past five financial years, the DWP for the Energex NSLP as a percentage of the Queensland TWP has varied from a low of 108% in 2011/12 to a high of 129% in 2009-10. In the 473 simulations for 2014-15 which exclude the carbon price, this percentage varies from 112% to 157% , for the simulations that include the carbon price this percentage varies from 106% to 144%. These results more than adequately cover the historical range. We note that the higher simulated percentages are associated with simulations where there is a higher correlation between the Queensland pool price and the Energex NSLP demand.

Notably, when the carbon price is included, the percentages tend to decrease by about 9 percentage points on average. This is primarily because the carbon price tends to have more effect in the off-peak periods when prices are influenced by the costs of the coal fired power stations and hence the carbon price is passed through to the pool price. In the peak periods, pool price outcomes are more influenced by opportunistic bidding behaviour and therefore are less influenced by the carbon price. Since the NSLP tends to be higher during the peak periods, the uplift in prices due to carbon is not as great as in the simple average Queensland TWP.

The comparison with actual outcomes over the past five years in Figure 9 demonstrates that the relationship between the Energex NSLP demand and Queensland pool prices in the 473 simulations is sound. Further, the cost of supplying the Energex NSLP in the simulations relates well to the Queensland pool price and covers the full range of possible outcomes for 2014-15. It also provides a sound cross check on the shape of the NSLP demand and its relationship with the Queensland demand.

Figure 9 **Annual DWP for Energex NSLP as percentage of annual TWP for Queensland for 473 simulations fro 2014-15 compared with actual outcomes in past years**



Source: AEMO historic pool price data and ACIL Allen results from PowerMark modelling

2.6.4 The effects of hedging

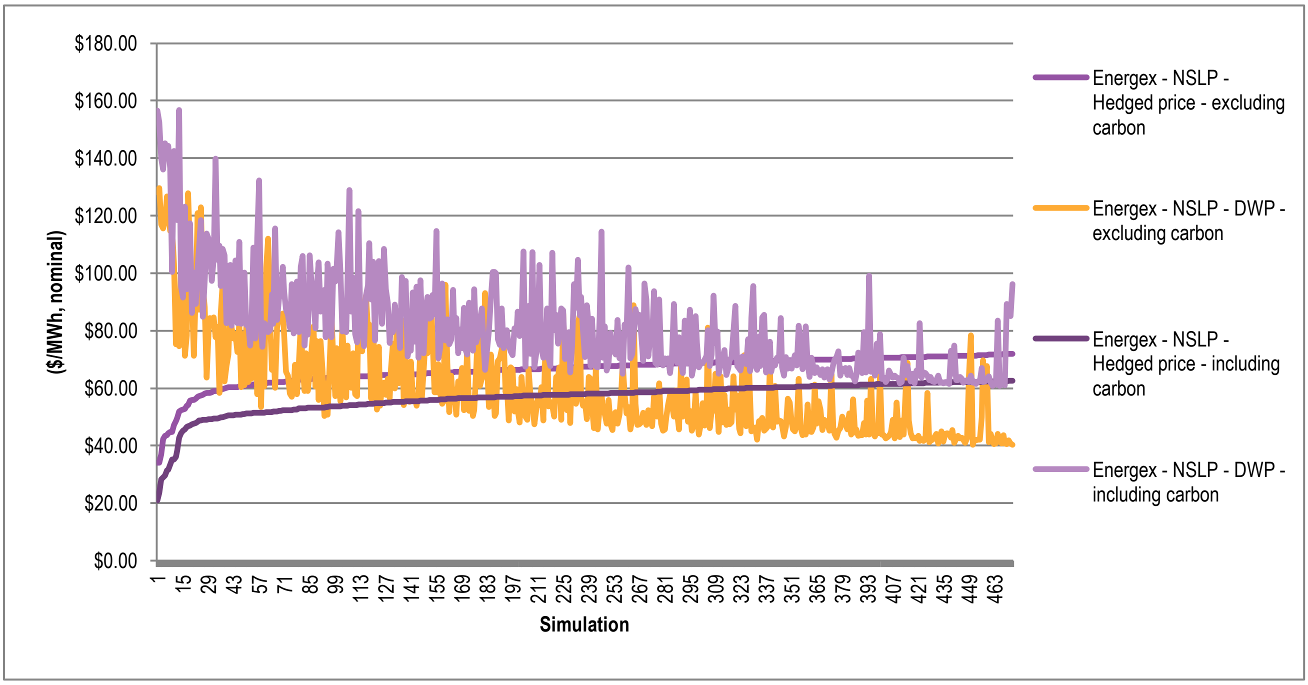
The ACIL Allen methodology uses a simple hedge book approach based on standard quarterly base and peak swaps and caps. The prices for these hedging instruments are taken from the futures market supplied by ASX Energy.

As hedge benefits are inversely related to pool prices, simulations with higher demand weighted pool prices usually produce lower hedged prices. Figure 10 shows that, under the ACIL Allen methodology, the higher estimates of supply costs including hedge effects are not associated with high demand and high pool price years. This is because, the benefits from the hedge strategy used in the methodology dominate the pool prices such that the higher prices after hedging is taken into account are generally related to the lower pool price simulations and vice versa.

In other words the current conservative hedging strategy has an inherent bias which rewards the retailer during price events in the pool that are higher than the contract price. This conservative hedging strategy has a significant cost in that hedges in excess of most expected demand outcomes must be acquired to put it into effect.

The graph below shows that although including the carbon price increases the DWP of the NSLP, it decreases the hedged outcome (keeping in mind the contract prices used in the hedge model in this instance are futures prices which in effect include the market risk adjusted price for carbon). This reflects a degree of over-hedging as a result of a conservative hedging strategy. The higher pool prices (due to carbon) relative to the risk weighted contract prices results in the retailer receiving more difference payments than in the case where the pool prices exclude carbon.

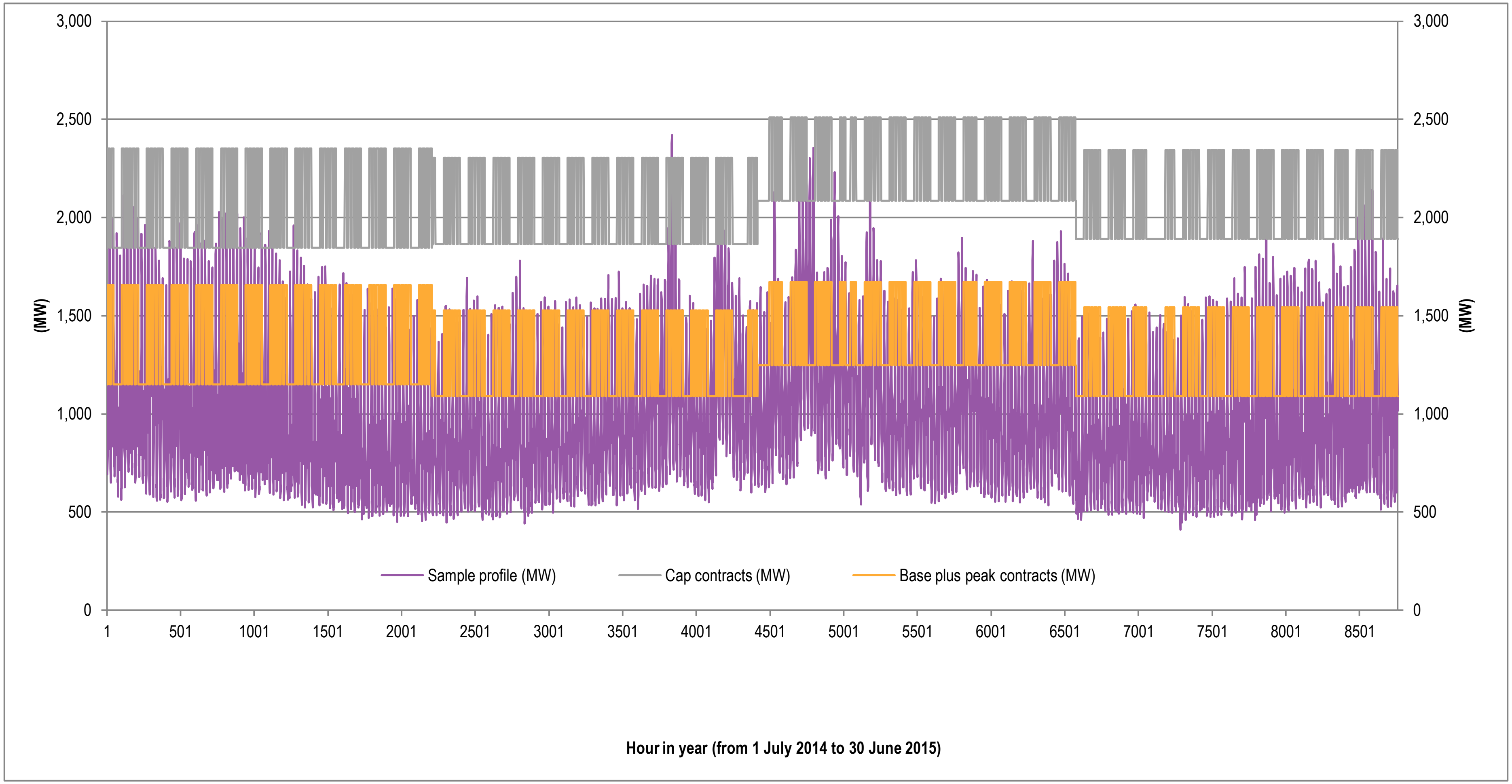
Figure 10 **Annual hedged price and DWP for Energex NSLP for the 473 simulations ($/MWh)**



Source: ACIL Allen modelling

Contract volumes are calculated by applying the hedging strategy to a simulated demand trace which has a peak demand and annual energy very close to the 50% POE peak demand and energy forecast. Once established, these contract volumes are then fixed across all 473 simulations when calculating the wholesale energy cost. The contract volumes used are shown in Figure 11.

Figure 11 **Contract volumes used in hedge modelling of 473 simulations for 2014-15 for Energex NSLP**



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.

ACIL Allen tested other hedging strategies. As an example we reduced the hedge volumes by setting the base contract volumes at the 50th percentile of the off-peak hourly loads and the cap volume at the 99th percentile of the peak loads in an attempt to better match the shape of the NSLP. This approach has three outcomes - it guarantees that one percent of hourly demands will breach the contract position, the correlation between hedged price outcomes and DWP changes from negative to effectively zero, and it reduces the gap between the hedged price outcomes excluding carbon and including carbon. This revised, more risky hedging strategy also results in a lower 95th percentile hedged price outcome. This lower price occurs because, while there is an increase in the percentage of time that demand breaches the contract position and results in an increase in pool price exposure, this is more than offset by reduced net settlement payments during periods where hourly pool prices are lower than the contract price (since the degree of over-hedging is lower).

ACIL Allen notes that the lower 95th percentile estimate using this contracting strategy increases the risk to the retailer and also the risk of understating the WEC and on this basis ACIL Allen does not propose to amend the existing hedging strategy.

2.7 Queries on pool price modelling

2.7.1 Transmission constraints

Origin Energy expressed concern that the pool price modelling does not allow for intra-regional transmission constraints which were the main cause of the high Queensland prices in January 2013.

As we responded to this query earlier, any model is, by definition, a simplification of the real word - whether it be heuristic, deterministic or statistical. ACIL Allen 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 Allen regularly tests the accuracy of *PowerMark* by undertaking back casting exercises and continues to be satisfied that the model is fit for purpose.

Based on the Powerlink APR we do not expect any significant transmission constraints in 2014-15.

2.7.2 Plant availability

Origin energy has requested that ACIL Allen publish in its pool modelling assumptions any departures from AEMO's medium term PASA and that assumptions regarding plant availability be provided to allow proper scrutiny of the pool modelling results.

The variation in modelling inputs such as plant availability and demand is sufficient to produce a wide variation in potential outcomes for 2104-15 which more than reasonably covers expected outcomes for that year. We do not consider that release of additional information will aid in scrutinising the pool modelling results.

2.7.3 Release of detailed modelling results

Stakeholders have requested that more information on the modelling assumptions and results be released such as individual plant capacity factors, interconnector flows, monthly peak and off-peak prices, etc. as this in their view would allow proper scrutiny of the results.

ACIL Allen 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 and continues to be satisfied that the model is fit for purpose. Furthermore, the range of pool prices from the modelling of the 473 simulations for 2014-15 described in Section 2.2 indicated that a very wide range of possible outcomes have been considered in the assessment of WEC for 2014-15.

ACIL Allen has assessed the information already released on the 473 simulations and believes that it is adequate for participants to assess the results.

2.8 Possible effects of "direct action"

AGL and Energy Australia have suggested that governments proposed "direct action" policy to reduce carbon emissions has the potential to increase energy costs in 2014-15 and that this needs to be considered.

ACIL Allen agrees that direct action has the potential to affect prices but because the policy is still in the formative stages it is not possible to make any adjustment for this policy. However, should this change between now and the Final Determination and the change was relatively certain then consideration would be given to incorporating an appropriate cost allowance in the WEC and or other energy costs.

2.9 95th percentile – allowance for risk

The purpose of using the 95th percentile is to properly account for the volatility in NEM price outcomes. QEnergy believe that the 99th percentile would be more appropriate and in keeping with the management practices of the organisation. In its supplementary submission to the 2013-14 Draft Determination Origin also argued for using the 99th percentile of the 473 annual hedged prices.

In ACIL Allen'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.

ACIL Allen notes that a 99th percentile 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 Allen 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.

2.10 Including a forward volatility premium

Ergon Energy have again argued for a forward volatility premium to be added to the WEC to reflect hedge price uncertainty between the time that modelling is completed and the time when retailers might finalise their hedge arrangements for each quarter of 2014-15.

Our position has not changed since this issue was raised by Ergon Energy following the 2013-14 draft Determination. Our position remains that futures contracts used in the methodology would be expected to include the option value associated with the length of time to expiry. Therefore in our view the methodology already reflects any volatility premium on the basis of our belief that, in general, the market is efficient and incorporates all the relevant factors which influence price. To accept Ergon's position we would need to accept that the market is not efficient.

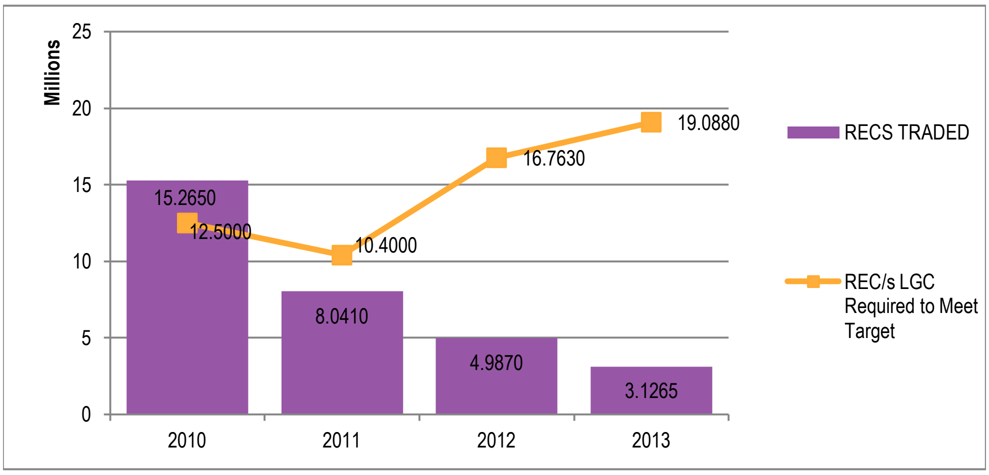
2.11 LGC prices

The QCA received submissions from four retailers which discussed approaches in estimating LRET compliance costs. Three of these submissions (AGL Energy, Origin Energy and Energy Australia) took the view that the most appropriate means of estimating the price of LGCs was through the calculation of the Long-Run Marginal Cost (LRMC) of creating LGCs.

Origin Energy also provided the following chart as evidence of declining spot volume trades experienced over the period 2013 to the end of August 2013.

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

Figure 12 **LGCs Traded vs Surrender Obligation, Cal 2010-13**



Note: Excludes trades where a bank was a counterparty. Cal 2013 partial year shows trades 1Jan to 31 Aug 2013. ACIL Allen has included data labels on the chart provided.

Source: Origin Energy, QCA Review of Regulated Electricity Prices 2014-15 presentation, 27 September, 2013

In comparison, Ergon Energy (EEQ) was generally supportive of ACIL Allen's approach in utilising forward market prices, but recommended extending the book-build period from two years to four years:[6]

Even though the methodology is not trade weighted, EEQ believes that the longer build period is more representative as this covers a longer period of time when more representative volumes of LGCs traded or quoted in the market. Therefore the price at which these were traded or quoted in the market better represented the true appetite of the market.

Further, EEQ are of the view that given there has been such uncertainty over the future of carbon legislation and Mandatory Renewable Energy Target (MRET), this has impacted on the number of LGCs coming to market and the decision to hedge exposure is delayed until more regulatory certainty is obtained. This is an anomaly which has been limited to the last 12 to 18 months. Should more certainty be gained around the future of the schemes the price could be markedly different.

Various scenarios have been considered regarding possible future carbon legislation and MRET changes which have all indicated that the price of LGCs are likely to increase above current price levels experienced over the past two years as there still exists a significant shortfall in the target. Furthermore, given that renewable energy generators may not receive a carbon portion of the electricity price (if carbon legislation is repealed) or would receive a lower carbon price (if the current carbon price is transitioned to a fully flexible price under an emissions trading scheme) then a higher LGC price would be required in order for projects to be made commercial.

[6] Ergon Energy Queensland Pty Ltd, Submission on the Regulated Retail Electricity Prices for 2014–15: Interim Consultation Paper, 6 September 2013, pg 12-14

Renewable energy generators are reluctant to sell LGCs at the current market price and can see the same changes in the regulatory environment that might lead to higher LGC prices. This is a contributing factor to the current low level of LGC liquidity.

Also EEQ considers that greater transparency is gained into the LGC market by utilising TFS for pricing observation rather than AFMA as AFMA contributions have been limited. TFS maintain market data dating back to 2009 on daily basis.

2.11.1 ACIL Allen's response to submissions

ACIL Allen recognises that in practice retailers build a portfolio of LGCs from a number of sources including:

- Direct investment in renewable generation projects
- PPAs written with renewable generators
- Spot and forward purchases transacted through brokers and direct trades with counterparties.

Of these, the only one which is traded regularly with transparent pricing are the spot and forward contracts transacted through brokers. A number of brokers are active in the trading of LGCs including NextGen, ICAP, TFS and BGC Partners amongst others. ACIL Allen understands that NextGen is the largest broker by volume. The Australian Financial Markets Association (AFMA) reports on pricing for LGCs based on a survey of respondents on a weekly basis.

ACIL Allen acknowledges that reported trade volumes have been declining over the last few years. Part of the large decline from 2010-11 is due to the split of the RET into the LRET/SRES components. In 2010 there were a multitude of small-scale certificate sellers from rooftop PV systems and solar hot water installers, whereas in recent years the number of sellers has declined due to it only being large-scale renewable projects creating LGCs.

It is not clear how Origin Energy has derived its turnover volumes but, even if we take these values at face value as being representative of actual total market turnover, the aggregate turnover for 2013 will be around 4.7 million LGCs (pro-rated for the full year). This equates to around 25% of the aggregate market liability for the 2013 compliance year and has a market value of around $165 million based on a LGC price of around $35. Whilst there are no hard and fast rules, in ACIL Allen's view, such turnover volumes would hardly lead one to characterise the spot market as 'illiquid'.

Volumes traded within the spot market may become a larger proportion of the annual target with targets for 2014 and 2015 being lower than 2013 and with the development of new renewable projects which aren't underpinned by PPAs such as Portland Stage 4 and Gullen Range wind farms. It is expected that these projects will sell their LGC output directly into the spot market or forward contract market.

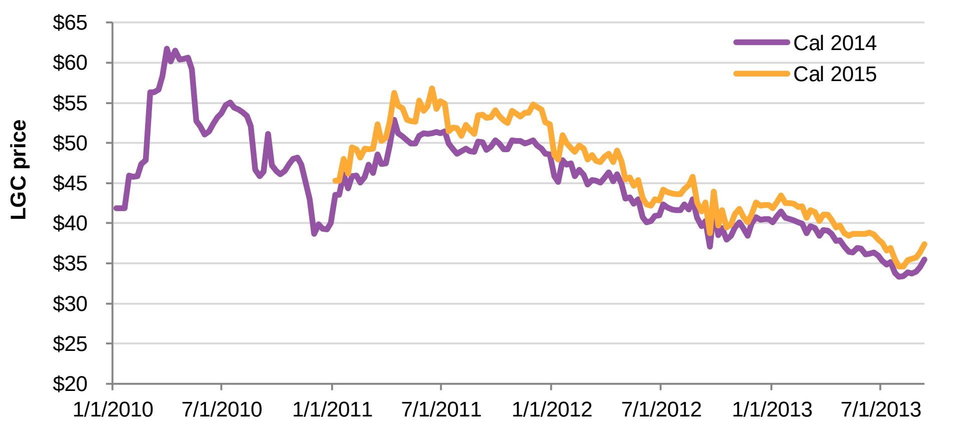
Ergon Energy suggested extending the book-build period to four years however this appears to be based on a notion that the current spot market is mispricing LGCs. Ergon expects the LGC price to rise based on response to policy factors such as a repeal of the Clean Energy Future legislation. Ergon Energy also suggests that "*Renewable energy generators are reluctant to sell LGCs at the current market price and can see the same changes in the* *regulatory environment that might lead to higher LGC prices. This is a contributing factor to the current low level of LGC liquidity*."

While it may be the case that some generators are taking a view on the market, withholding certificates in expectation of higher future prices, the current market price provides the consensus view of the impacts of possible policy driven changes. The market price for LGC 2014 and 2015 forwards has declined by around $15/certificate since around mid-2011 as shown in Figure 13. If market participants, were taking a view that prices were going to rise in the near-term then speculative long positions would be expected to increase and spot prices would be expected to rise accordingly until such trades no longer made commercial sense on a risk-reward basis.

In reality there are risks to LGC prices on the upside and downside. Whilst repeal of the CEA is clearly positive for LGC prices, the potential for downward revision to annual targets resulting from the RET review scheduled for early 2014 is a negative for LGC prices. There is also some uncertainty around the scheme's long-term viability in the context of declining wholesale electricity demand.

ACIL Allen continues to hold the view that the prices within the spot and futures market represent the most reliable indicator of the current market consensus view of the price of LGCs. ACIL Allen's preference is to maintain the two year book-build methodology as this does not give weight to much older price data and market views which have since been modified given the new information available to the market.

Figure 13 **LGC prices for 2014 and 2015 LGC forwards**



Source: ACIL Allen based on AFMA LGC price data

We acknowledge that the AFMA LGC price data being relied upon is survey based[7], is not trade-weighted and is at a weekly resolution. These are all limitations of the data source. ACIL Allen's preference would be to calculate a trade-weighted average price based on daily data. However, given the disparity of brokers involved in the industry and the lower

[7] The data includes bids, asks and mid-points excluding outliers for multiple respondents

level of transparency of broker data (particularly trade volume) such an approach is in our view not practicable.

LRMC of LGCs is not a useful measure

The submissions of AGL Energy, Origin Energy and Energy Australia all call for the calculation and use of LRMC is determining the most appropriate price for LGCs. As noted within Origin Energy's submission, LRMC was recently used in IPARTs Review of Regulated Retail Electricity Prices 2013-16.

Firstly, as stated above, ACIL Allen believes that transparent market prices provide a much better indicator of current prices compared with any modelled outcomes. A modelled price should only be used where market pricing is not available.

There are a number of problems of using a LRMC approach for LGC prices. LRMC is a long run (a period of time over which all factors of production may be varied) and forward looking concept and in the case of LGC would be expected to largely relate to future wind which is currently (and for the foreseeable future) the lowest cost form of large-scale renewable power generation.

There are a number of methods for calculating LRMC often classified under two broad headings, being the brownfields and greenfields approaches. Brownfields is the more traditional approach in that it considers the existing market status and then assesses the long run costs of meeting an incremental increase in demand (in this case demand for LGC). Greenfields generally assumes that the complete market demand is met by new supply – in effect more of an average cost concept of meeting all existing plus future supply over a specified time period.

For the purpose of the following discussion we use a greenfields approach as it is simpler to calculate. In effect we are interested in the long run average costs of new build wind generation. Taking a specific example of a 25 year wind project with the following settings:

- $2,300/kW installed overnight capacity cost; 18 month construction period
- $50,000/MW/year fixed operating and maintenance cost; zero variable cost
- 35% capacity factor
- WACC of 7% (post-tax real).

This yields a calculated LRMC of around $95/MWh.[8] This means that such a project would need to achieve revenues that equate to $95/MWh on average in real terms of the 25 years in order to be commercially viable. However there are two components to this revenue: black energy revenue from sales of electricity and LGC revenue. There are a large number of factors which will impact black energy prices over this 25 year period including the supply demand balance in the market and the carbon pricing assumption.

Assuming no future changes to the renewable energy scheme, to obtain the estimated levelised LGC price required, one needs to have a view on the levelised black energy

[8] There would likely be broad agreement that the LRMC of wind is currently somewhere in the vicinity of $85-110/MWh (noting that the assumed capacity factor is a principal determinant in this calculation).

component of this revenue stream over the 25 year project life (including any future changes with respect to carbon). To illustrate the effect of black prices we consider three scenarios as detailed in Table 1 which result in different levelised costs for the LGC revenue component (assumes no changes to the LRET scheme). This analysis assumes a 2015 wind installation which would receive 16 years of LGC revenue (the LRET ends in 2030) and 25 years of black energy revenue. In each case the present value of the revenue stream is the same at $3,386 million per MW installed.

Table 1 **LRMC of LGC prices based on various black energy scenarios**

Black price scenario	Required levelised LGC price
$55 flat in real terms	49.06
$55 increasing at 2% in real terms	35.66
$55 decreasing at 2% in real terms	59.41

Note: Assumes a 2015 installation (16 years of LGC creation; 25 years of black energy revenue)

Clearly the use of LRMC in estimating LGC prices requires a significant shift in modelling approach across to LRMC and requires at least a 25 year outlook for black energy prices. It is also dependent on an estimate of the LRMC of the marginal renewable energy supplier which for wind alone covers a possible range from $85/MWh to 110/MWh.

While the above discussion shows that using LRMC to determine LGC prices is largely impractical, there are broader issues with respect to the use of LRMC similar to its use in estimating wholesale energy costs. In particular, any calculation of LRMC 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 2014-15, except as a matter of coincidence.

2.12 STC Costs

2.12.1 STP estimate

QEnergy are concerned at the poor forecasting performance of the regulator and suggest that a risk margin be added to the estimated Small scale Technology Percentage (STP) to account for what QEnergy describes as a systematic error.

ACIL Allen 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 historical 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 Allen is of the view that a non-binding STP by the Clean Energy Regulator provides the best available estimate for future binding STPs.

2.12.2 Prices

ACIL Allen notes that most submissions agree with the use of the $40.00 as set by the Clearing House.

ACIL Allen acknowledges there is an active market for STCs. However, historical 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 sets the STP at the level where the market just clears valuing STCs at the Clearing House price of $40.00.

3 Estimation of wholesale energy cost (WEC)

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

3.1 Outline of approach

The approach adopted by ACIL Allen 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 demand profiles for 473 simulations of 2014-15, estimated using ACIL Allen'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 Allen does not have sufficient independently verified information on the costs of the hedging benefits of any such instruments to incorporate them into the energy cost estimates. Furthermore ACIL Allen is of the view that the traded market derivatives provide a sound basis for evaluating the actual cost of energy to retailers. In addition, 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

Following assessment of the submissions to the Authorities consultation paper and subsequent workshop ACIL Allen is satisfied that its existing approach is reasonable for estimating WEC.

3.2.1 Developing 43 simulations of demand traces each representing 2014-15

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

- 43 years of three hourly capital city temperature data from 1970-71 to 2012-13
- NEM regional demand traces for four years from 2009-10 to 2012-13[9]
- Energex and Ergon NSLP demand traces for four years from 2009-10 to 2012-13

[9] There are a number of reasons for limiting the analysis to the 2009-10 to 2012-13 time series. First, the process used to develop the 43 simulated demand sets, described below, also develops, simultaneously, 43 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 is only partly complete.

- 10%, 50% and 90% POE demand and annual energy forecast parameters from the AEMO 2013 NEFR
- forecast installed solar PV capacity and output for each NEM region for 2014-15 from the AEMO 2013 NEFR
- estimates of installed solar PV capacity and output for each NEM region for the years 2009-10 to 2012-13 from the AEMO 2013 NEFR.
- forecast LNG load in Queensland in 2014-15 from the AEMO 2013 NEFR

The first step in the process is to extract the actual demand traces for four years 2009-10 to 2012-13 from the AEMO published data and include the NEM regional totals, the NSLP and controlled demands 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 demand in the Energex area. The Ergon Energy NLSP is used to estimate the wholesale energy costs applying to unmetered demand and >100MWh customers in the Ergon Energy area.

The extracted NEM regional demands are then adjusted by adding to the half hourly demand values an estimate of the rooftop solar PV output. The estimated rooftop output is based on historical data provided by AEMO in the 2013 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.

The NEM and settlement class demands for 2009-10 through 2011-12 are scaled so that in broad terms they are at a comparable level to the 2012-13 demands. This is done by assessing the change in underlying energy between 2009-10 and 2012-13 for periods unaffected by weather variations.

This results in four years of demand data scaled to 2012-13 levels for each NEM region and settlement class. These demands are then used to populate 43 demand sets each representing 2012-13 based on the 43 weather (temperature) years.

39 simulated demand 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 demands (from 2009-10 to 2012-13) is adopted by finding the best matching daily temperature profile (given the month 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 four years 2009-10 to 2012-13 across all NEM regions simultaneously. Once the day with the same day type and season in the four years from 2009-10 to 2012-13 that best matches the temperature profile of the day in question is identified, then all the associated NEM regional and settlement class demand 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 demands traces and settlement class demand traces.

The 39 simulated demand sets together with the actual (scaled) demand sets for 2009-10 to 2012-13 give a total of 43 demand traces representing 2012-13.

The 43 sets of NEM regional demand traces are then scaled to match the 2014-15 demand and energy forecasts from the NEFR (which have been adjusted by removing the projection for LNG[10] and adding the projected contribution of rooftop solar PV). The scaling process is applied simultaneously across the 43 demand traces so that the total energy of the aggregate 43 demand traces is equal to 43 times the forecast annual energy in each NEM region. The maximum of the annual peak demands from the 43 demand traces is scaled to match the 10% POE summer demand forecasts in each region. Similarly, the median of the annual peak demands from the 43 demand traces is scaled to the 50% POE summer demand forecasts in each region. Finally, the minimum of the annual peak demands from the 43 simulated demand traces is scaled to the 90% POE summer demand forecasts in each region.

The 43 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.

Finally the forecast of the LNG load is converted to a half hourly profile which is assumed to grow linearly from the winter 2014 forecast to the 2014-15 summer forecast to the 2015 winter forecast. This load is added to each of the 43 annual half hour profiles for Queensland to produce the loads to be used in the pool price modelling.

3.2.2 Developing the 43 NSLP simulated demand sets

There are a number of additional steps used to establish the 43 simulated demand sets for the NSLPs which, because of the need to consider the effects of solar photovoltaic (PV) on demand, we 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 Allen to establish the 43 simulations of these NSLPs representing 2014-15:

Step 1. Add the contribution of rooftop solar PV to the Queensland demands and the NSLP demands (it is assumed that 71 percent of solar output is attributed to the Energex NSLP and 29 percent is attributed to the Ergon NSLP - based on analysis of installed capacity by postcode)

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

Step 3. Calculate the average half hour demand for each of the 43 simulated years for 2012-13 for both the Queensland NEM demand and the NSLPs for each of the 48 period types.

Step 4. For each half hour in the 43 simulations for 2012-13 calculate the differences between the simulated value and the corresponding average value (from Step 3) for Queensland and the NSLPs.

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[10] LNG is removed in building the demand sets because it is projected to grow strongly throughout the year and distorts the scaling of demand - it is added back later in the process.

Step 5. For each of the 43 simulations for the year 2012-13, in each half hourly interval calculate the difference that each of the NSLPs difference is (from Step 4) as a percentage of the Queensland difference (from Step 4).

Step 6. For each half hourly interval and for each of the 43 simulations, calculate the difference between the Queensland demand for 2012-13 and Queensland for 2014-15.

Step 7. For each half hourly interval and for each of the 43 simulations, for each of the NSLPs apply the percentage (from Step 5) to the difference (from Step 6). This is an estimate of the NSLP contribution to variations in the Queensland demand.

Step 8. For each half hourly interval and for each of the 43 simulations, add the results (from Step 7) to each of the NSLPs for 2012-13 and deduct the assumed contribution of solar PV to give the 43 simulated demand traces representing NSLPs in 2014-15.

This process is designed to allow estimation of the 43 simulated years representing 2014-15 for the Energex and Ergon NSLPs based on the NSLPs contribution to variations in the Queensland demand.

3.2.3 Developing 11 plant outage sets for the NEM

PowerMark incorporates the availability of each generation unit for each half-hour of the year. Using binomial probability theory ACIL Allen 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 or outages occur coincident with peak demand, volatile prices usually result. The process used to simulate the outage sets allows these sorts of coincidences to be represented appropriately.

3.2.4 Running *PowerMark* using the 43 demand sets and 11 outage sets

PowerMark is run to estimate the hourly pool prices for 2014-15 for 473 simulations by (43 demand and 11 outage sets) developed using the steps described above both with and without carbon.

Fuel price and other plant cost and other assumptions used in the *PowerMark* modelling are those developed by ACIL Allen over the past 15 years and are consistent with ACIL Allen's latest internal Reference Case. These assumptions come from a wide variety of sources and are regularly monitored and updated as market conditions change.

The modelling results from the 473 simulations (43 simulated demand sets and 11 outage sets) are compared with actual market outcomes since commencement of the market. This involves investigation of the shape and level of the price duration curve particularly the upper tail, annual time and load weighted prices, number and level of prices above $300/MWh.

3.2.5 Determine hedging strategy and volumes

A standard hedging strategy for each settlement class is developed by setting the parameters to calculate the base, peak and cap contract volumes based on the median demand/price year. ACIL Allen has used the same strategy as employed for 2013-14. 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 summary statistics of the simulated demand traces. Once established, these contract volumes are then fixed across all 473 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 across all 43 simulated demand sets.
- Peak period contract volume is set to equal the 90th percentile of quarterly peak period demands across all 43 simulated demand sets minus the base contract volume.
- Cap contract volume set at 105 per cent of the median of the 43 quarterly peak demands minus the base and peak contract volumes.

For last year's Determination, ACIL Allen tested a range of hedging strategies around the selected strategy and is satisfied that the selected strategy represents a conservative and low risk strategy for a retailer.

3.2.6 Estimating contract prices (risk adjusted carbon case)

Contract prices for the 2014-15 year were estimated using ASX Energy daily settlement prices and trade volumes since the contract was listed and up until and including the cut-off date of 15 October 2013.

The method used to estimate contract prices is the trade-weighted average of daily settlement prices.

Table 2 shows the estimated quarterly swap and cap contract prices for the Draft Determination.

Table 2 **Quarterly base, peak and cap estimated contract prices ($/MWh) - Risk adjusted carbon case – 2014-15**

	Q3 2014	Q4 2014	Q1 2015	Q2 2015
Base	$50.54	$51.96	$63.91	$48.85
Peak	$59.52	$66.00	$90.50	$53.50
Cap	$3.39	$5.68	$13.37	$3.75

Source: ACIL Allen analysis using ASX Energy data up to, and including 15 October 2013

Average base contract price for 2014-15 are some $3.71/MWh lower than that used in the Final Determination for 2013-14. Average peak contract prices are $1.92/MWh lower and cap prices are marginally higher than those used in the Final Determination for 2013-14. This results generally because the lower risk adjusted allowance for carbon in the 2014-15 contract prices price given the increased uncertainty for carbon pricing in 2014-15 compared with 2013-14, more than offsets a higher underlying price without carbon.

Contract prices without carbon pricing (No carbon case)

Contract prices *without* carbon pricing are found by subtracting the risk adjusted carbon allowance from the ASX futures contract prices in Table 2

The risk adjusted carbon allowance is found by calculating the average of daily differences between the ASX Energy futures and NextGen over-the-counter (OTC) contracts with the AFMA addendum[11], where daily prices existed. Using this method, the risk adjusted carbon allowance for 2014-15 is estimated to be $7.00/MWh. This method applies to the base and peak contracts only. The carbon price does not heavily influence prices greater than $300, and therefore cap contract prices are unchanged (see Figure 8).

Table 3 shows the estimated quarterly base, peak and cap contract prices without carbon pricing (used in the No carbon case) for the Draft Determination.

Table 3 **Quarterly base, peak and cap estimated contract prices ($/MWh) - No carbon price case – 2014-15**

	Q3 2014	Q4 2014	Q1 2015	Q2 2015
Base	$43.54	$44.96	$56.91	$41.85
Peak	$52.52	$59.00	$83.50	$46.50
Cap	$3.39	$5.68	$13.37	$3.75

Source: ACIL Allen analysis using ASX Energy and NextGen data up to, and including 15 October 2013

Base contracts for 2014-15 without carbon are $10.90/MWh higher on average than that used for the Final Determination for 2013-14 and peak contracts are $12.70/MWh higher. This reflects an anticipation of some tightening in the supply-demand balance with the coming of the LNG loads and higher fuel prices (mainly gas prices) compared with 2013-14.

Contract prices with carbon pricing

Contract prices with the full carbon pricing assumed (used in the Carbon case) are found by adding the carbon allowance to the contract prices without carbon pricing in Table 3.

The carbon allowance is calculated by multiplying the average NEM intensity of 0.87 tCO_2-e/MWh by the reference carbon price of $25.4/$tCO_2$-e. Using this method, the carbon allowance is estimated to be $22.10/MWh.

[11] OTC contract with the AFMA addendum

Again, this method applies to the base and peak contracts only. The carbon price does not heavily influence prices greater than $300, and therefore cap contract prices are unchanged.

Table 4 shows the estimated quarterly swap and cap contract prices with carbon pricing for the Draft Determination.

Table 4 **Quarterly base, peak and cap estimated contract prices ($/MWh) - Carbon price case – 2014-15**

	Q3 2014	Q4 2014	Q1 2015	Q2 2015
Base	$65.63	$67.06	$79.00	$63.95
Peak	$74.62	$81.10	$105.60	$68.60
Cap	$3.39	$5.68	$13.37	$3.75

Source: ACIL Allen analysis using ASX Energy and NextGen data up to, and including 15 October 2013

Base contracts for 2014-15 without carbon are $11.39/MWh higher on average than that used for the Final Determination for 2013-14 and peak contracts are $13.18/MWh higher. This reflects an increase in the carbon price and an anticipation of some tightening in the supply-demand balance with the coming of the LNG loads and higher fuel prices (mainly gas prices) compared with 2013-14.

The following charts show daily settlement prices and trade volumes for ASX Energy quarterly base futures, peak futures and cap contracts up to and including 15 October 2013.

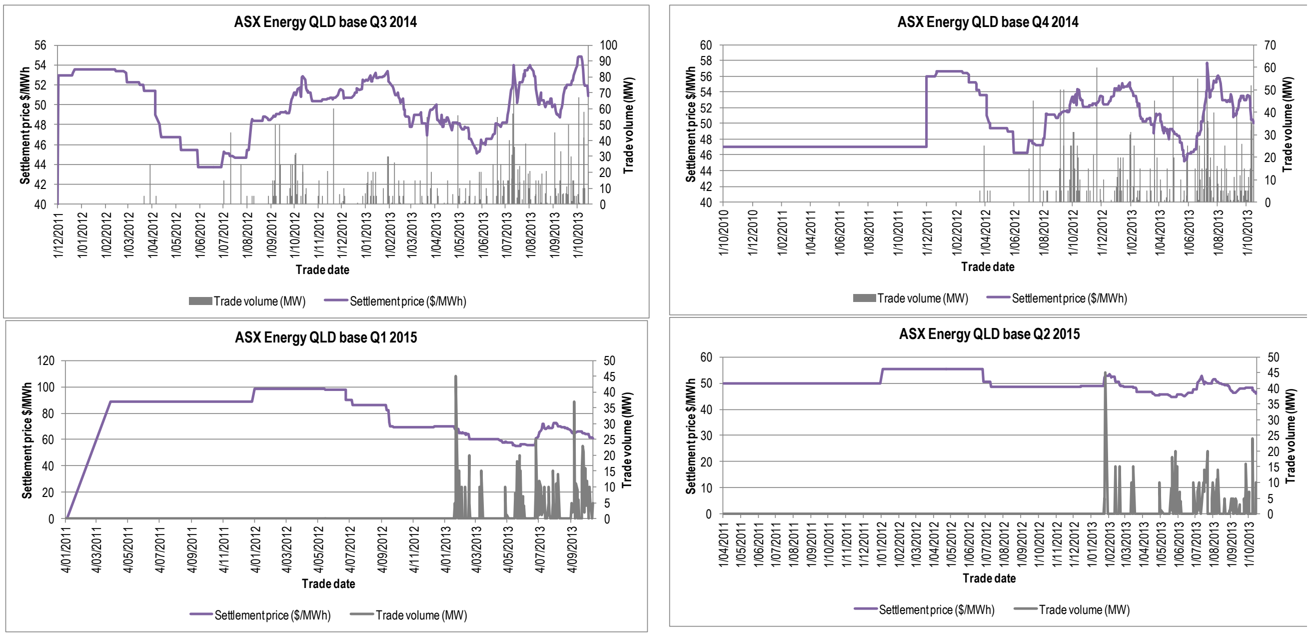
Base futures have traded strongly in 2014, with total volumes between 2,090 MW (Q4 2014) and 2,494 MW (Q3 2014). Volumes are lower in 2015, between 447MW (Q2 2015) and 590MW (Q1 2015). However, these volumes are consistent with the 2013-14 equivalent quarterly futures as at 15 October 2012.

Peak futures have lower trade volumes of between 5 MW (Q4 2014) and 11 MW (Q31 2014), and no trade volume in 2015, which is consistent with peak futures trade volumes at the same time last year.

Cap futures trade volumes are also consistent with last year and range from 0 MW (Q2 2015) to 187MW (Q3 2014).

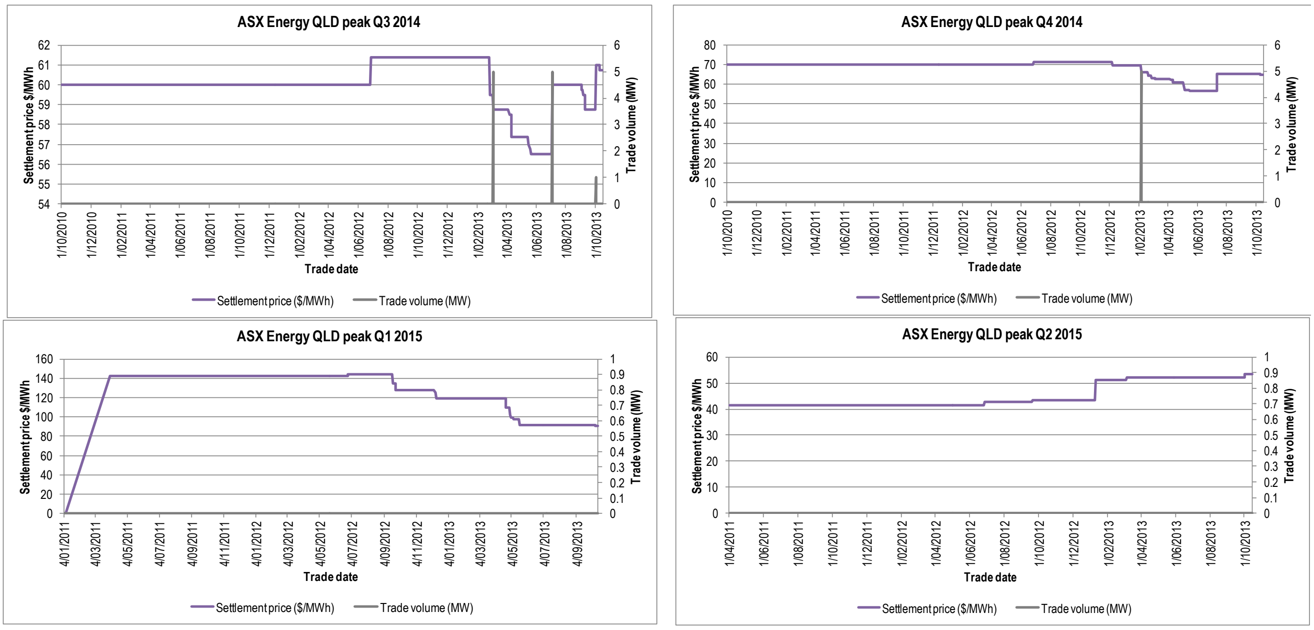
Whilst trade volumes for Q1 and Q2 2015 futures appear low, they are, in our experience, at normal levels for this time of year. We expect trade volumes for 2015 futures to begin to increase during early 2014 as we approach the commencement of the contract dates.

Figure 14 **Time series of trade volume and price – ASX Energy QLD BASE futures for Q3 2014, Q4 2014, Q1 2015 and Q2 2015**



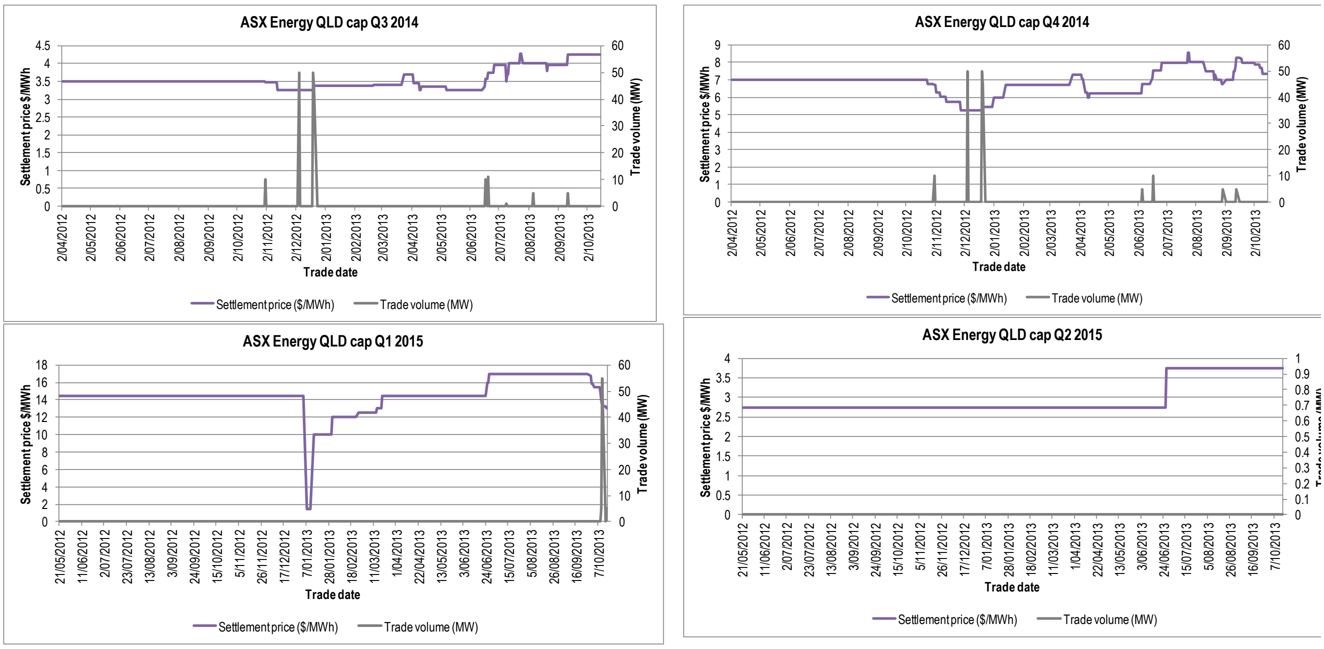
Data Source: ASX Energy data up to, and including 15 October 2013.

Figure 15 **Time series of trade volume and price – ASX Energy QLD PEAK futures for Q3 2014, Q4 2014, Q1 2015 and Q2 2015**



Data Source: ASX Energy data up to, and including 15 October 2013.

Figure 16 **Time series of trade volume and price – ASX Energy QLD $300 CAP contracts for Q3 2014, Q4 2014, Q1 2015 and Q2 2015**



Data Source: ASX Energy data up to, and including 15 October 2013.

3.2.7 Application of transmission and distribution losses

Prices at 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 average Marginal Loss Factors (MLF) for transmission losses from the node to major supply points in the distribution networks are applied.

The transmission loss factors from the Queensland reference node to the distribution network for Energex and Ergon Energy's east zone area are based on the average energy-weighted marginal loss factors (MLFs) for the Energex and Ergon Energy east zone TNI's. This analysis resulted in a transmission loss factor of 1.008 for Energex and 1.053 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 2013-14 as the data for 2014-15 is not yet available.

The estimated transmission and distribution loss factors for the settlement classes used in the Draft Determination shown in Table 5 are the same as those used for the Final determination for 2013-14 as there has been no update in the loss factors by AEMO. For the Final determination we expect to use the 2014-15 loss factors.

Table 5 **Estimated transmission and distribution loss factors for Energex and Ergon Energy's east zone**

Settlement classes	Distribution loss factor (DLF)	Transmission marginal loss factor (MLF)	Total loss factors (MLFxDLF)
Energex - NSLP - residential and small business and unmetered supply	1.064	1.008	1.073
Energex - Control tariff 9000	1.064	1.008	1.073
Energex - Control tariff 9100	1.064	1.008	1.073
Ergon Energy - NSLP - SAC HV, CAC and ICC	1.033	1.053	1.088
Ergon Energy - NSLP - SAC demand and street lighting	1.078	1.053	1.135

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

For the Draft Determination ACIL Allen has applied the same methodology as used in the Final Determination for 2013-14 so that it aligns with the application of the transmission marginal loss factors (MLF) and distribution loss factors (DLF) used by AEMO.

As described by AEMO12, to arrive at prices at the customer terminal (price at load connection point) the MLF and DLF are applied to the prices at the regional reference node (RRN) as follows:

Price at load connection point = RRN Spot Price * (MLF * DLF)

3.2.8 Calculation of wholesale energy costs for 2014-15

Using the contract prices and volumes with the projected hourly pool prices for the 473 simulations in the hedge model provides 473 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 473 simulated annual hedged prices is used as the estimate of the WEC for 2014-15.

For the control load tariffs ACIL Allen 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.

[12] See Page 23 of the AEMO publication *Treatment of loss factors in the national electricity market- July 2012*

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:

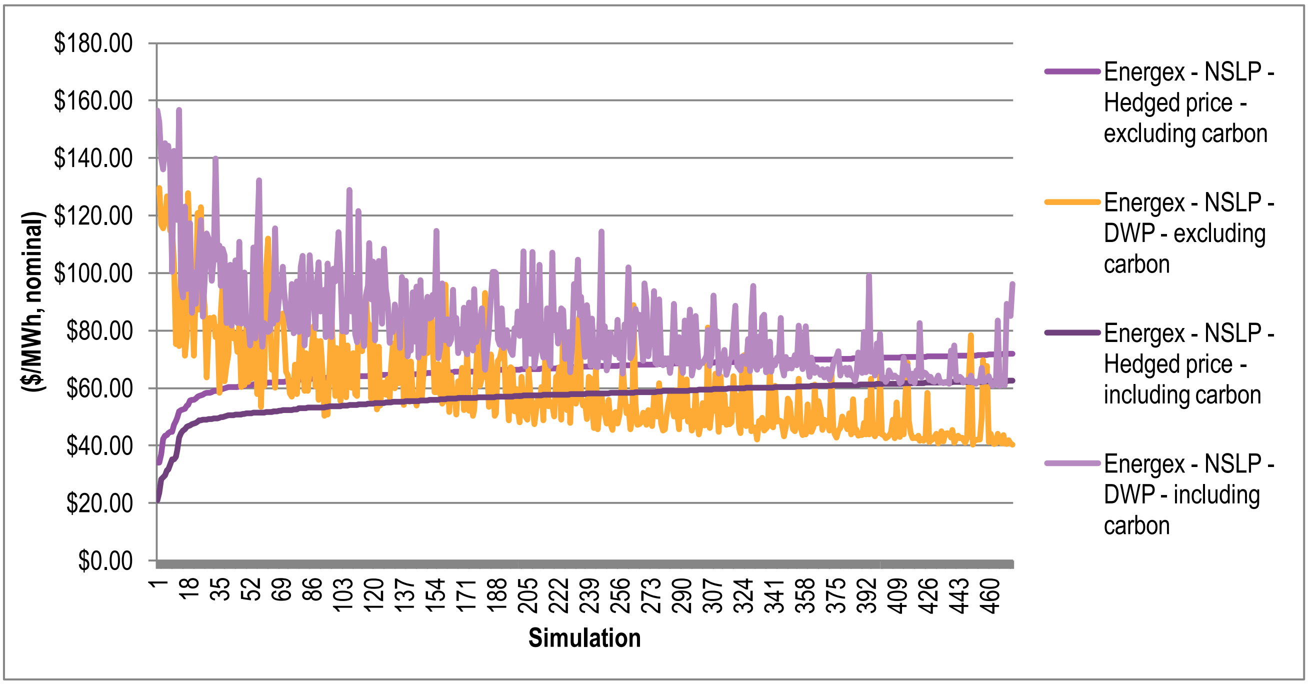
- annual reports
- gas price modelling using *GasMark*
- announced contractual arrangements for fuel
- ACIL Allen estimates
- Non-sensitive information provided by clients
- AEMO reports

Detailed data is provided in Appendix C.

3.4 Summary of WEC estimates

Figure 17 demonstrates that there is limited variation in the WEC across the 473 simulation years after 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 demand. 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 17 **Annual hedged price and DWP for Energex NSLP for the 473 simulations ($/MWh)**



Source: ACIL Allen modelling

Table 6 shows the results for the WEC modelling for the Draft Determination <u>with the risk weighted carbon price and represents ACIL Allen's best estimate of the WEC given the uncertainty around the carbon price</u>. It includes an allowance for the transmission and distribution losses and the estimate of the cost at the customer terminals.

Table 6 **Estimated WEC ($/MWh, nominal) for 2014-15 – Risk adjusted carbon case**

Settlement class	WEC at the Queensland reference node ($/MWh)	Total transmission and distribution loss factor (MLFxDLF)	WEC at the customer terminal ($/MWh)
Energex - NSLP - residential and small business	$71.14	1.073	$76.33
Energex - Control tariff 9000 (31)	$45.85	1.073	$49.20
Energex - Control tariff 9100 (33)	$58.61	1.073	$62.89
Energex - NSLP - unmetered supply	$71.14	1.073	$76.33
Ergon Energy - NSLP - SAC HV, CAC and ICC	$63.35	1.088	$68.92
Ergon Energy - NSLP - SAC demand and street lighting	$63.35	1.135	$71.90

Note: Based on pool modelling and contract prices assuming carbon price of $25.40
Source: ACIL Allen analysis

The prices estimated for the Draft Determination for 2014-15 in the risk adjusted carbon case for the settlement classes vary from an increase of $1.83/MWh for the NSLP related classes to a decline of $1.30/MWh for the 9000 control tariff. The reductions in the 2014-15 contract prices compared with the estimates used for the Final Determination for 2013-14 are offset by the interaction between hedged volumes and contract prices and pool volumes and prices.

Annual average swap contract prices proposed for the 2014-15 Draft Determination for the risk adjusted carbon case are around $3.00/MWh (or about 5%) lower than those used for the 2013-14 Final Determination. The small decline is a result of a significant increase in contracts without carbon of around $12.00/MWh (or around 30%) which is more than offset by a decline in the risk adjusted allowance for the carbon price in the swap contracts which is estimated at $7.00/MWh in 2014-15 Draft Determination compared with $21.44/MWh for the 2013-14 Final Determination.

The significant increase in contract prices without carbon is consistent with ACIL Allen's pool price modelling results which show similar levels and trends to the swap contract prices. This means that the pool price modelling results reflect the views of future prices generally held by market participants.

The large increase in prices without carbon is associated with two important developments both of which are linked to the LNG developments in Queensland during 2014-15 and these are:

- the tightening of the supply-demand balance for electricity due to increased electricity demand for water pumping and gas compression required for gas production to supply the Gladstone LNG plants

- significantly higher gas prices in 2014-15 compared with 2013-14 with market prices applying in the pool modelling rather than individual contract prices (ACIL Allen has observed that generators are already beginning to on-sell some of their lower priced contracted gas at higher market prices rather than use it to generate electricity.).

The large decline in the allowance in swap contracts for carbon reflects the increased level of uncertainty over the future of carbon pricing in 2014-15 compared with 2013-14 when the market considered it certain to apply.

3.4.1 Carbon and No carbon cases

The tables below summarise the WEC for the two additional scenarios requested by the QCA, the with the full carbon price (Carbon case) and with no carbon price (No carbon case)

Table 7 **Estimated WEC ($/MWh, nominal) for 2014-15 – Carbon case**

Settlement class	WEC at the Queensland reference node ($/MWh)	Total transmission and distribution loss factor (MLFxDLF)	WEC at the customer terminal ($/MWh)
Energex - NSLP - residential and small business	$82.99	1.073	$89.05
Energex - Control tariff 9000 (31)	$59.29	1.073	$63.62
Energex - Control tariff 9100 (33)	$71.23	1.073	$76.43
Energex - NSLP - unmetered supply	$82.99	1.073	$89.05
Ergon Energy - NSLP - SAC HV, CAC and ICC	$76.61	1.088	$83.35
Ergon Energy - NSLP - SAC demand and street lighting	$76.61	1.135	$86.95

Note: Based on pool modelling and contract prices assuming carbon price of $25.40
Source: ACIL Allen analysis

The WEC for the Carbon case is an average of $14.07/MWh higher than the Final Determiniation for 2013-14. The higher contract prices are mainly responsible.

Table 8 **Estimated WEC ($/MWh, nominal) for 2014-15 – No carbon case**

Settlement class	WEC at the Queensland reference node ($/MWh)	Total transmission and distribution loss factor (MLFxDLF)	WEC at the customer terminal ($/MWh)
Energex - NSLP - residential and small business	$61.46	1.073	$65.95
Energex - Control tariff 9000 (31)	$36.58	1.073	$39.25
Energex - Control tariff 9100 (33)	$49.90	1.073	$53.55
Energex - NSLP - unmetered supply	$61.46	1.073	$65.95
Ergon Energy - NSLP - SAC HV, CAC and ICC	$54.91	1.088	$59.74
Ergon Energy - NSLP - SAC demand and street lighting	$54.91	1.135	$62.32

Note: Based on pool modelling and contract prices assuming no carbon price
Source: ACIL Allen analysis

The WEC for the No carbon case is an average of $14.00/MWh higher than the Final Determination for 2013-14. The higher contract prices are mainly responsible.

4 Estimation of other energy costs

The other energy costs (OEC) estimates for the Draft Determination provided in this section consist of:

- Costs associated with compliance with the Renewable Energy Target (RET) encompassing:
  - LRET
  - SRES
- 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[13]) 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 Allen has used the following:

- Large-scale Generation Certificate (LGC) market prices from AFMA[14]
- LRET targets for 2014 and 2015 of 16,950 GWh and 18,850 GWh respectively, as published by the Clean Energy Regulator (CER)
- Default Renewable Power Percentages (RPPs)[15] for 2014 and 2015 as published by CER, of 9.46 per cent and 10.52 per cent, respectively.
- CER's non-binding estimates for Small-scale Technology Percentage (STP) of 8.98 and 8.49 per cent for 2014 and 2015, respectively[16]
- CER clearing house price for 2014 and 2015 for Small-scale Technology Certificates (STCs) of $40/MWh(see Section 2.12.2).

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[13] 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.

[14] AFMA data includes weekly prices up to and including 15 October 2013, which is the cut-off date for all relevant market-based data used in the Draft Determination for 2014-15 tariffs.

[15] The CER publishes default RPP values as required under Regulation 23 for all future years of the scheme. The default RPP effectively pro-rates the current RPP by the change in the future GWh target over the current year target.

[16] Published on 15 March 2013. The 2014 and 2015 non-binding STP estimates are based on the modelling prepared for the recently published 2013 STP. The binding STP estimate for 2014 will be published by 31 March 2014.

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.

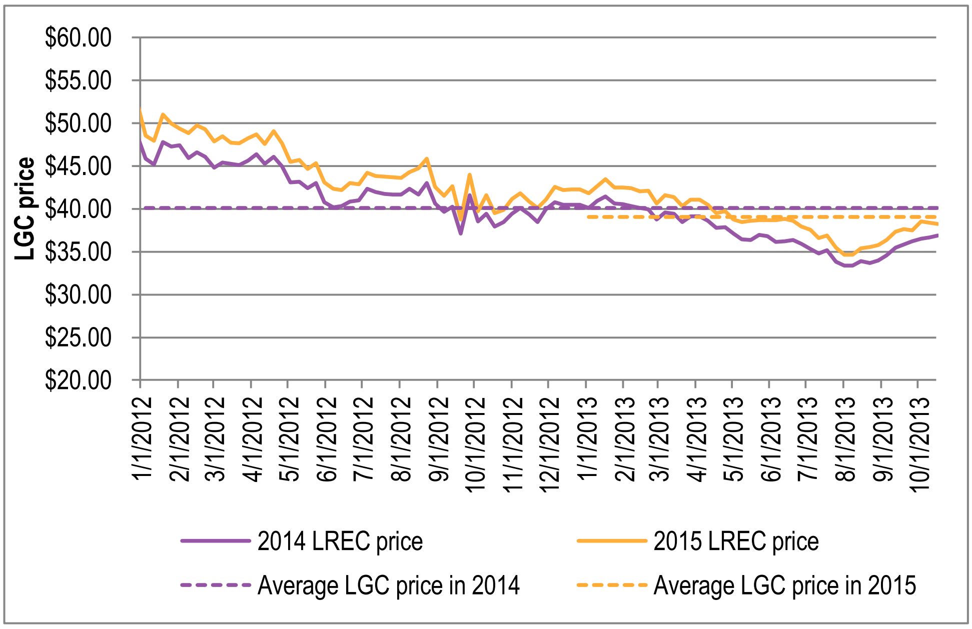
ACIL Allen has estimated the average LGC price using forward looking weekly market prices for LGCs published by the Australian Financial Markets Association (AFMA) [17]..

The LGC price used in assessing the cost of the scheme for 2014-15 is found by averaging the forward prices for 2014 and 2015 during the two years prior to the commencement of 2014 and 2015. This assumes that LGC coverage is built up over a two year period (see Figure 18). The average LGC prices calculated from the AFMA data are $40.06/MWh for 2014 and $39.02/MWh for 2015**:**

- 2014 is based on prices starting on 5 January 2012 capturing 94 weeks
- 2015 is based on prices starting on 3 January 2013 capturing 42 weeks.

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

Figure 18 **LGC futures prices for 2014 and 2015 (nominal $/LGC)**



Source: AFMA and ACIL Allen analysis

ACIL Allen calculates the cost of complying with the LRET in 2014 and 2015 by multiplying the RPPs in 2014 and 2015 by the average LGC prices in 2014 and 2015, respectively. The cost of complying with the LRET in 2014-15 was found by averaging the calendar estimates.

Therefore, ACIL Allen estimates the cost of complying with the LRET scheme to be $3.95/MWh in 2014-15 as shown in Table 9.

Table 9 **Estimated cost of LRET – 2014-15**

	2014	2015	Cost of LRET 2014-15
RPP %	9.46%	10.52%	
Average LGC price ($/LGC, nominal)	$40.06	$39.02	
Cost of LRET ($/MWh, nominal)	$3.79	$4.11	$3.95

Source: CER, AFMA, ACIL Allen analysis

4.1.2 SRES

The cost of SRES for calendar years 2014 and 2015 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 2014-15.

The non-binding STPs published by CER are as follows:

- 8.98 per cent for 2014 (equivalent to 16.7 million STCs as a proportion of total estimated liable electricity for the 2014 year)

- 8.49 per cent for 2015 (equivalent to 15.8 million STCs as a proportion of total estimated liable electricity for the 2015 year).

ACIL Allen estimates the cost of complying with SRES to be $3.49/MWh in 2014-15 as set out in Table 10.

Table 10 **Estimated cost of SRES – 2014-15**

	2014	2015	Cost of SRES 2014-15
Non-binding STP %	8.98%	8.49%	
STC clearing house price ($/STC, nominal)	$40.00	$40.00	
Cost of SRES ($/MWh, nominal)	$3.59	$3.40	$3.49

Source: CER, ACIL Allen analysis

Combining the LRET and SRES costs for both schemes yields a total cost of $7.44/MWh for 2014-15.

4.2 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 and the Electricity Consumer Advocacy Panel.

Based on AEMO's *Electricity Final Budget & Fees 2013-14*, which projects fees for 2014-15, the total NEM fee for 2014-15 is $0.39/MWh[18], up from $0.37/MWh in 2013-14.

4.3 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 2014-15, the cost of ancillary services is estimated to be $0.39/MWh.

4.4 Prudential costs

This section covers cost estimates for AEMO and hedge prudential costs.

[18] The total NEM fees include the following components: market customer allocated fee, general administration, advocacy panel, national transmission plannerand full retail contestability (FRC) operation fees.

4.4.1 AEMO prudential costs

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 43 days

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

- a future risk-weighted mean pool price of $54.37
- a volatility factor of 2, based on published AEMO volatility factors for 2013[19]
- Loss factor of 1.05,

results in an MCL of $5,265.56.

However as this applies for a rolling 43 days it actually covers 43 MWh of retailer purchases. Hence the portion of the MCL applicable to each MWh is $5,266/43 = $122.45.

The cost of funding a bank guarantee for the MCL associated with the single MWh is assumed to be a 2.5% annual charge[20] for 43 days or 2.5%*(43/365) = 0.288%. Applying this funding cost to the single MWh charge of $122.45 gives $0.361/MWh.

4.4.2 Hedge prudential costs

ACIL Allen 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 9% on average for a base contract

[19] http://www.aemo.com.au/Electricity/Settlements/Prudentials/NEM-Regional-Volatility-Factor

[20] This is the handling charge for a guarantee facility which is not drawn down.

- the intra commodity spread charge currently set at $3,300 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 $53.77[21] and applying the above factors gives an average initial margin for each quarter of around $14,300 for a 1 MW quarterly contract. In order to allow for some ongoing future uncertainty we have rounded this to $15,000 per 1 MW quarterly contract. Dividing this by the average hours in a quarter then gives an initial margin of $6.85 per MWh. Assuming a funding cost of 9.72% (the approved WACC for Energex as proposed by QEnergy) but adjusted for an assumed 3% return on cash lodged with the clearing house gives a net funding cost of 6.72%. Applying 6.72% to the initial margin per MWh gives a prudential cost for hedging of $0.46/MWh.

ACIL Allen 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 Allen considers that the base contract assessment is a reasonable reflection of the prudential obligations faced by retailers.

4.4.3 Total prudential costs

Adding the AEMO and hedge prudential costs gives a total prudential requirement as set out in Table 11.

Table 11 **Total prudential costs ($/MWh) – 2014-15**

Cost category	Cost ($/MWh)
AEMO pool	$0.36
Hedge	$0.46
Total	$0.82

Source: ACIL Allen analysis

4.5 Summary of other energy cost estimates

In summary, the 'other energy costs' components for 2014-15 are estimated to be $9.04/MWh. These costs are summarised in Table 12.

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

Table 12 **Summary of OEC ($/MWh) at the regional reference node – 2014-15**

Cost category	Fees ($/MWh)
LRET	$3.95
SRES	$3.49
NEM fees	$0.39
Ancillary services	$0.39
Prudential costs	$0.82
Total other energy costs	$9.04

Note: All costs are presented at the Queensland regional reference node. Numbers may not add due to rounding.
Source: ACIL Allen 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 13 to Table 15 for the Risk adjusted carbon case, Carbon case and No carbon case respectively. The estimated costs in the table include both the WEC and the OEC.

Table 13 **Estimated TEC for 2014-15 - Risk adjusted carbon case**

Settlement class	WEC at the Queensland reference node ($/MWh)	Renewable energy and market fees at the Queensland reference node ($/MWh)	Total transmission and distribution loss factor (MLFxDLF)	TEC at the customer terminal ($/MWh)
Energex - NSLP - residential and small business	$71.14	$9.04	1.073	$86.03
Energex - Control tariff 9000 (31)	$45.85	$9.04	1.073	$58.90
Energex - Control tariff 9100 (33)	$58.61	$9.04	1.073	$72.59
Energex - NSLP - unmetered supply	$71.14	$9.04	1.073	$86.03
Ergon Energy - NSLP - SAC HV, CAC and ICC	$63.35	$9.04	1.088	$78.76
Ergon Energy - NSLP - SAC demand and street lighting	$63.35	$9.04	1.135	$82.16

Note:
Source: ACIL Allen analysis

Table 14 **Estimated TEC for 2014-15 - Carbon case**

Settlement class	WEC at the Queensland reference node ($/MWh)	Renewable energy and market fees at the Queensland reference node ($/MWh)	Total transmission and distribution loss factor (MLFxDLF)	TEC at the customer terminal ($/MWh)
Energex - NSLP - residential and small business	$82.99	$9.04	1.073	$98.75
Energex - Control tariff 9000 (31)	$59.29	$9.04	1.073	$73.32
Energex - Control tariff 9100 (33)	$71.23	$9.04	1.073	$86.13
Energex - NSLP - unmetered supply	$82.99	$9.04	1.073	$98.75
Ergon Energy - NSLP - SAC HV, CAC and ICC	$76.61	$9.04	1.088	$93.19
Ergon Energy - NSLP - SAC demand and street lighting	$76.61	$9.04	1.135	$97.21

Note:
Source: ACIL Allen analysis

Table 15 **Estimated TEC for 2014-15 - No carbon case**

Settlement class	WEC at the Queensland reference node ($/MWh)	Renewable energy and market fees at the Queensland reference node ($/MWh)	Total transmission and distribution loss factor (MLFxDLF)	TEC at the customer terminal ($/MWh)
Energex - NSLP - residential and small business	$61.46	$9.04	1.073	$75.65
Energex - Control tariff 9000 (31)	$36.58	$9.04	1.073	$48.95
Energex - Control tariff 9100 (33)	$49.90	$9.04	1.073	$63.25
Energex - NSLP - unmetered supply	$61.46	$9.04	1.073	$75.65
Ergon Energy - NSLP - SAC HV, CAC and ICC	$54.91	$9.04	1.088	$69.58
Ergon Energy - NSLP - SAC demand and street lighting	$54.91	$9.04	1.135	$72.58

Note:
Source: ACIL Allen analysis

Appendix A Ministerial Delegation

DELEGATION TO QCA

ELECTRICITY ACT 1994
Section 90AA(1)

DELEGATION

I, Mark McArdle, the Minister for Energy and Water Supply, in accordance with the power of delegation in section 90AA(1) of the *Electricity Act 1994* (the Act), delegate to the Queensland Competition Authority (QCA) the function under section 90(1) of the Act of deciding the prices that a retail entity may charge its non-market customers for customer retail services for the tariff years from 1 July 2013 to 30 June 2016.

The following are the Terms of Reference of the price determination:

Terms of Reference

1. These Terms of Reference apply for each of the tariff years in the delegation period.

2. In each tariff year of the delegation period, QCA is to calculate the notified prices and publish an annual price determination, in the form of a tariff schedule, in accordance with these Terms of Reference.

3. In accordance with section 90(5)(a) of the Act, in making a price determination for each tariff year QCA must have regard to all of the following:

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

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

   (c) the matters set out in paragraph 5 of these Terms of Reference.

4. In accordance with section 90(5)(b) of the Act, QCA may have regard to any other matter that QCA considers relevant.

5. The matters that QCA is required by this delegation to consider are:

   (a) Uniform Tariff Policy - QCA must consider the Government's Uniform Tariff Policy, which provides that, wherever possible, non-market customers of the same class should have access to uniform retail tariffs and pay the same notified price for their electricity supply, regardless of their geographic location;

   (b) Time of Use Pricing – QCA must consider whether its approach to calculating time-of-use tariffs can strengthen or enhance the underlying network price

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signals and encourage customers to switch to time-of-use tariffs and reduce their energy consumption during peak times;

(c) Framework - QCA must use the Network (N) plus Retail (R) cost build-up methodology when working out the notified prices and making the price determination, where N (network cost) is treated as a pass-through and R (energy and retail cost) is determined by QCA;

(d) When determining the N components for each regulated retail tariff for each tariff year, QCA must consider the following:

(i) for residential and small business customers, that is, those who consume less than 100 megawatt hours (MWh) per annum - basing the network cost component on the network charges to be levied by Energex;

(ii) for large business customers in the Ergon Energy distribution region who consume 100MWh or more per annum - basing the network cost component on the network charges to be levied by Ergon Energy given that, from 1 July 2012, large business customers in the Energex distribution region no longer have access to notified prices;

(e) Transitional Arrangements - QCA must consider:

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

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

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

Interim Consultation Paper

6. As part of each annual price determination, QCA must publish an interim consultation paper identifying key issues to be considered when calculating the N

and R components of each regulated retail electricity tariff and transitioning relevant retail tariffs over the three-year delegation period.

7. QCA must publish a written notice inviting submissions about the interim consultation paper. The notice must state a period during which anyone can make written submissions to QCA about issues relevant to the price determination.

8. QCA must consider any submissions received within the consultation period and make them available to the public, subject to normal confidentiality considerations.

Consultation Timetable

9. As part of each annual price determination, QCA must publish an annual consultation timetable within two weeks after submissions on the interim consultation paper are due, which can be revised at the discretion of QCA, detailing any proposed additional public papers and workshops that QCA considers would assist the consultation process.

Workshops and additional consultation

10. As part of the Interim Consultation Paper and in consideration of submissions in response to the Interim Consultation Paper the QCA must consider the merits of additional public consultation (workshops and papers) on identified key issues.

11. Specifically, given the three-year period of the delegation the QCA must conduct a public workshop on the energy and retail cost components used to determine regulated retail tariffs prior to the release of the 2013-14 Draft Determination.

Draft Price Determination

10. As part of each annual price determination, QCA must investigate and publish an annual report of its draft price determination on regulated retail electricity tariffs, with each tariff to be presented as a bundled price, for the relevant tariff year. The draft price determination must also specify the carbon cost allowances for the relevant tariff year.

11. QCA must publish a written notice inviting submissions about the draft price determination. The notice must state a period during which anyone can make written submissions to QCA about issues relevant to the draft price determination.

12. QCA must consider any submissions received within the consultation period and make them available to the public, subject to normal confidentiality considerations.

Final Price Determination

13. As part of each annual price determination, QCA must investigate and publish an annual report of its final price determination on regulated retail electricity tariffs, with each tariff to be presented as a bundled price, for the relevant tariff year, and gazette the bundled retail tariffs. The final price determination must also specify the carbon cost allowances for the relevant tariff year.

Timing

14. QCA must make its reports available to the public and, at a minimum, publicly release for each tariff year the papers and price determinations listed in paragraphs 6 to 13.

15. QCA must publish the interim consultation paper for the 2013-14 tariff year no later than one month after the date of this Delegation and no later than 30 August before the commencement of the subsequent tariff years.

16. QCA must publish the draft price determination on regulated retail electricity tariffs on 22 February 2013 for the 2013-14 tariff year and no later than 13 December before the commencement of the subsequent tariff years.

17. QCA must publish the final price determination on regulated retail electricity tariffs for each relevant tariff year, and have the bundled retail tariffs gazetted, no later than 31 May each year.

18. This Delegation revokes my previous Delegation issued on 5 September 2012.

DATED this 12th day of February 2013.

[redacted]

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

Appendix B Consultancy Terms of Reference

Terms of Reference

Review of Regulated Retail Electricity Tariffs and Prices for 2014-15

Assessment of Energy Costs

16 July 2013

1. Project Background

On 12 February 2013, 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. 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 Authority requires the assistance of a consultant to estimate the cost of energy for these annual reviews.

ACIL Allen (then ACIL Tasman) undertook this work for the Authority for its 2013-14 review. At that time, the Authority offered an 'in principle' agreement for ACIL Allen to be engaged to provide similar advice for its 2014-15 and 2015-16 reviews subject to it not undertaking work that might be seen as a conflict of interest and to the proposed costs being reasonable.

The Authority is about to initiate its 2014-15 review and invites ACIL Allen to provide it with a proposal to meet the requirements of this terms of reference.

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 2014-15. 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 2014-15 estimates for:

(a) wholesale energy costs;

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

(c) NEM fees, ancillary services charges and prudential costs; and

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

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

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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	Late September
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	18 October 2013
Stakeholder Workshop	• Conduct a workshop with interested parties on changes to the consultant's proposed approach, following feedback on the Draft Determination	To be negotiated.
Final Report	• Address submissions on the Draft Report • Outline the consultant's final approach • Provide final cost estimates	4 April 2014

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 late July 2013 and is expected to be completed by 31 May 2014.

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 requirements 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 26 July 2013.

For further information concerning this consultancy, please contact Rimu Nelson on (07) 3222 0577.

Proposals should be submitted to:

Rimu Nelson

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	2014	2015
Barcaldine	$7.25	$15.32
Braemar 1	$2.94	$3.01
Braemar 2	$5.40	$7.70
Callide B	$1.47	$1.51
Callide C	$1.47	$1.51
Condamine	$9.85	$9.74
Darling Downs	$6.81	$9.45
Gladstone	$1.75	$1.79
Kogan Creek	$0.84	$0.86
Mackay GT	$33.89	$34.74
Millmerran	$0.95	$0.97
Mt Stuart	$33.89	$34.74
Oakey	$4.63	$12.17
Roma	$9.85	$9.74
Stanwell	$1.56	$1.60
Swanbank E	$4.59	$4.66
Tarong	$1.12	$1.15
Tarong North	$1.12	$1.15
Townsville	$4.43	$4.53
Yarwun	$3.88	$3.95
New Entrant CCGT	$9.85	$9.74
New Entrant CCGT-CCS	$9.85	$9.74
New Entrant SC COAL	$1.63	$1.64
New Entrant IGCC-CCS	$1.63	$1.64
New Entrant OCGT	$12.32	$12.17
New Entrant SC COAL-CCS	$1.63	$1.64

Source: ACIL Allen assumptions

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 Allen assumptions

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

Table C3 **Details of Queensland generators used in pool price modelling for 2014-15**

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, 2013 $)
AGL	Oakey	OAKEY1	Gas turbine	Natural gas	141	0	1.5%	32.6%	0.0513	0.0054	$9.98
AGL	Oakey	OAKEY2	Gas turbine	Natural gas	141	0	1.5%	32.6%	0.0513	0.0054	$9.98
AGL	Townsville	YABULU	Gas turbine combined cycle	Natural gas	160	133	3.0%	46.0%	0.0513	0.0054	$1.09
AGL	Townsville	YABULU2	Gas turbine combined cycle	Natural gas	80	67	3.0%	46.0%	0.0513	0.0054	$1.09
Alinta	Braemar 1	BRAEMAR1	Gas turbine	Natural gas	168	90	1.5%	30.0%	0.0513	0.0054	$8.23
Alinta	Braemar 1	BRAEMAR2	Gas turbine	Natural gas	168	90	1.5%	30.0%	0.0513	0.0054	$8.23
Alinta	Braemar 1	BRAEMAR3	Gas turbine	Natural gas	168	90	1.5%	30.0%	0.0513	0.0054	$8.23
CS Energy	Callide B	CALL_B_1	Steam turbine	Black coal	350	200	7.0%	36.1%	0.095	0.002	$1.25
CS Energy	Callide B	CALL_B_2	Steam turbine	Black coal	350	200	7.0%	36.1%	0.095	0.002	$1.25
CS Energy	Callide C	CPP_3	Steam turbine	Black coal	405	200	4.8%	36.5%	0.095	0.002	$2.84
CS Energy	Gladstone	GSTONE1	Steam turbine	Black coal	280	110	5.0%	35.2%	0.0921	0.002	$1.24
CS Energy	Gladstone	GSTONE2	Steam turbine	Black coal	280	110	5.0%	35.2%	0.0921	0.002	$1.24
CS Energy	Gladstone	GSTONE3	Steam turbine	Black coal	280	110	5.0%	35.2%	0.0921	0.002	$1.24
CS Energy	Gladstone	GSTONE4	Steam turbine	Black coal	280	110	5.0%	35.2%	0.0921	0.002	$1.24
CS Energy	Gladstone	GSTONE5	Steam turbine	Black coal	280	110	5.0%	35.2%	0.0921	0.002	$1.24
CS Energy	Gladstone	GSTONE6	Steam turbine	Black coal	280	110	5.0%	35.2%	0.0921	0.002	$1.24
CS Energy	Kogan Creek	KPP_1	Steam turbine	Black coal	750	350	8.0%	37.5%	0.094	0.002	$1.31
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	$2.49
ERM	Braemar 2	BRAEMAR5	Gas turbine	Natural gas	153	150	1.5%	30.0%	0.0513	0.0054	$8.23
ERM	Braemar 2	BRAEMAR6	Gas turbine	Natural gas	153	0	1.5%	30.0%	0.0513	0.0054	$8.23
ERM	Braemar 2	BRAEMAR7	Gas turbine	Natural gas	153	0	1.5%	30.0%	0.0513	0.0054	$8.23
InterGen	Callide C	CPP_4	Steam turbine	Black coal	405	200	4.8%	36.5%	0.095	0.002	$1.25
InterGen	Millmerran	MPP_1	Steam turbine	Black coal	425.5	130	4.7%	36.9%	0.092	0.002	$2.95
InterGen	Millmerran	MPP_2	Steam turbine	Black coal	425.5	130	4.7%	36.9%	0.092	0.002	$2.95

C-3

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, 2013 $)
Origin	Darling Downs	DDPS1	Gas turbine combined cycle	Natural gas	630	270	6.0%	46.0%	0.0513	0.002	$1.09
Origin	Mt Stuart	MSTUART1	Gas turbine	Liquid Fuel	146	0	3.0%	30.0%	0.0697	0.0053	$9.39
Origin	Mt Stuart	MSTUART2	Gas turbine	Liquid Fuel	146	0	3.0%	30.0%	0.0697	0.0053	$9.39
Origin	Mt Stuart	MSTUART3	Gas turbine	Liquid Fuel	126	0	3.0%	30.0%	0.0697	0.0053	$9.39
Origin	Roma	ROMA_7	Gas turbine	Natural gas	40	0	3.0%	30.0%	0.0513	0.0054	$9.98
Origin	Roma	ROMA_8	Gas turbine	Natural gas	40	0	3.0%	30.0%	0.0513	0.0054	$9.98
QGC	Condamine	CPSA	Gas turbine combined cycle	Natural gas	140	0	3.0%	48.0%	0.0513	0.002	$1.09
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	$11.85
Stanwell - Tarong	Barron Gorge	BARRON-2	Hydro	Hydro	30	15	1.0%	100.0%	0	0	$11.85
Stanwell - Tarong	Kareeya	KAREEYA1	Hydro	Hydro	21	8	1.0%	100.0%	0	0	$6.46
Stanwell - Tarong	Kareeya	KAREEYA2	Hydro	Hydro	21	8	1.0%	100.0%	0	0	$6.46
Stanwell - Tarong	Kareeya	KAREEYA3	Hydro	Hydro	18	8	1.0%	100.0%	0	0	$6.46
Stanwell - Tarong	Kareeya	KAREEYA4	Hydro	Hydro	21	8	1.0%	100.0%	0	0	$6.46
Stanwell - Tarong	Mackay GT	MACKAYGT	Gas turbine	Fuel oil	34	0	3.0%	28.0%	0.0697	0.0053	$9.39
Stanwell - Tarong	Stanwell	STAN-1	Steam turbine	Black coal	360	190	7.0%	36.4%	0.0904	0.002	$3.34
Stanwell - Tarong	Stanwell	STAN-2	Steam turbine	Black coal	360	190	7.0%	36.4%	0.0904	0.002	$3.34
Stanwell - Tarong	Stanwell	STAN-3	Steam turbine	Black coal	360	190	7.0%	36.4%	0.0904	0.002	$3.34
Stanwell - Tarong	Stanwell	STAN-4	Steam turbine	Black coal	360	190	7.0%	36.4%	0.0904	0.002	$3.34
Stanwell - Tarong	Swanbank E	SWAN_E	Gas turbine combined cycle	Coal seam methane	385	150	3.0%	47.0%	0.0513	0.0054	$1.09

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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, 2013 $)
Stanwell - Tarong	Tarong	TARONG#1	Steam turbine	Black coal	350	140	8.0%	36.2%	0.0921	0.002	$7.80
Stanwell - Tarong	Tarong	TARONG#2	Steam turbine	Black coal	350	140	8.0%	36.2%	0.0921	0.002	$7.80
Stanwell - Tarong	Tarong	TARONG#3	Steam turbine	Black coal	350	140	8.0%	36.2%	0.0921	0.002	$7.80
Stanwell - Tarong	Tarong	TARONG#4	Steam turbine	Black coal	350	140	8.0%	36.2%	0.0921	0.002	$7.80
Stanwell - Tarong	Tarong North	TNPS1	Steam turbine	Black coal	443	175	5.0%	39.2%	0.0921	0.002	$1.49

Data source: ACIL Allen PowerMark database

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