ACIL ALLEN CONSULTING

REPORT TO
QUEENSLAND COMPETITION AUTHORITY

20 NOVEMBER 2014

ESTIMATED ENERGY COSTS

2015-16 RETAIL TARIFFS

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

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ACIL ALLEN (2014) ESTIMATED 2015-16 ENERGY COSTS FOR QCA DRAFT DETERMINATION

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1 Introduction

ACIL Allen has been engaged by the Queensland Competition Authority (the QCA) to provide advice on the energy related costs likely to be incurred by a retailer to supply customers on notified retail prices for 2015-16.

Retail prices generally consist of three components:

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

ACIL Allen's engagement relates to the energy costs component only. In accordance with the Ministerial Delegation (the Delegation), which is published on the QCA's website[1], and the Consultancy Terms of Reference (TOR) provided by the QCA and which is also published on the QCA's website[2], 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 2015-16; i.e. non-market customers. Although the QCA's determination will apply only in the Ergon Energy distribution area, the TOR specifically requests that the analysis cover the same tariff classes as covered in the analyses for the 2013-14 and 2014-15 determinations.

This report provides estimates of the expected energy costs for use by the QCA in its Draft Determination. These estimates will be revised for the Final Determination in early 2014 and will take into account feedback from the Draft Determination as well as any updated data applicable to the analysis.

This report also provides responses to submissions made by various parties following the QCA's Interim Consultation Paper, *Regulated Retail Electricity Prices 2015-16* (September 2014), where those submissions refer to the cost of energy in regulated retail electricity prices.

[1] http://www.qca.org.au/getattachment/e0aa30e0-e806-45f1-a51f-44b1edd8d128/Ministerial-Delegation.aspx

[2] http://www.qca.org.au/getattachment/0fa9b74d-502a-422e-b23b-90890011ca1e/ACIL-Allen-Terms-of-Reference.aspx

2 Overview of approach

2.1 Introduction

In preparing advice on the estimated energy costs, 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 2015 to 30 June 2016.

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.

2.2 Components of the energy cost estimates

Energy costs comprise:

- wholesale energy costs for various demand profiles
- costs of complying with state and federal government policies, including the Renewable Energy Target (RET)
- National Electricity Market (NEM) fees, ancillary services charges and costs of meeting prudential requirements
- energy losses incurred during the transmission and distribution of electricity to customers.

2.3 Methodology

ACIL Allen's methodology is a continuation of the methodology used to provide advice to the QCA for the 2013-14 and 2014-15 Determinations (please refer to ACIL Allen's report for the

2014-15 Draft Determination[3] and the 2014-15 Final Determination[4] for details of the methodology).

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 added to the wholesale energy costs and the total is then adjusted for network losses.

Unlike previous years, as the Clean Energy Act and associated legislation was repealed in July 2014, there is no carbon price in the analysis.

2.3.1 Wholesale energy costs

As with the 2013-14 and 2014-15 review, ACIL Allen continues to use the market hedging approach for estimating the WEC for 2015-16.

We have utilised the:

- stochastic demand model to develop 44 weather influenced simulations of hourly demand traces for each of the tariff profiles – using temperature data from 1970-71 to 2013-14 and demand data for 2010-11 to 2013-14
- stochastic outage model to develop 11 power station availability simulations
- energy market models to run 484 simulations of hourly pool prices of the NEM using the stochastic demand traces and power station availabilities as inputs
- analysis of contract data to estimate contract prices
- hedge model taking the above analyses as inputs to estimate a distribution of hedged prices for each tariff class.

We have then analysed the distribution of outcomes produced by the above approach to provide a risk adjusted estimate of the WEC for each tariff class.

We have continued to rely on the Australian Energy Market Operator (AEMO) as a source for the various demand data required for the analysis. The QCA provided ACIL Allen with access to ASX Energy data for the purpose of estimating contract prices.

The peak demand and energy forecasts for the demand profiles are referenced to the current AEMO demand forecasts for Queensland and take into account past trends and relationships between the NSLPs and the Queensland region demand. At this stage of the process, it is our assessment that the AEMO medium series demand projection for 2015-16 provided in AEMO's 2014 National Electricity Forecasting Report (NEFR) is the most reasonable demand forecast for the purposes of this analysis.

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[3] http://www.qca.org.au/getattachment/4cb8b436-7b50-4328-8e27-13f51a4d021c/ACIL-Allen-Estimated-Energy-Costs-2015-15-Retail-T.aspx

[4] http://www.qca.org.au/getattachment/9be567a8-92e2-4d53-85f0-3781e4f8662f/ACIL-Allen-Final-Report-Estimated-Energy-Costs-for.aspx

2.3.2 Renewable energy policy costs

Energy costs associated with the Large-scale Renewable Energy Target (LRET) and the Small-scale Renewable Energy Scheme (SRES) have been estimated using the latest price information from AFMA and renewable energy percentages published by the Clean Energy Regulator (CER). Retailer compliance with these schemes operates on a calendar year basis and hence estimates are required for both 2015 and 2016 calendar years, with the costs averaged to estimate the 2015-16 financial year costs.

To estimate the costs to retailers of complying with both the LRET and SRES, ACIL Allen uses the following elements:

- historical Large-scale Generation Certificate (LGC) market prices sourced from AFMA
- currently legislated LRET GWh targets for 2015 and 2016
- estimates of the Renewable Power Percentage (RPP) for 2015[5] and 2016
- estimates for the Small-scale Technology Percentage (STP) for 2015[6] and 2016 under the SRES
- The fixed clearing house price for Small-scale Technology Certificates (STCs).

2.3.3 Other energy costs

Market fees and ancillary service costs are estimated based on data and policy documents published by AEMO.

Prudential costs, both AEMO and to support hedging, are more complex and need to take into account:

- the AEMO assessed maximum credit limit (MCL)
- the future risk-weighted pool price
- participant specific risk adjustment factors
- AEMO published volatility factors
- futures market prudential obligation factors, including:
  - the price scanning range (PSR)
  - the intra commodity spread charge
  - the spot isolation rate.

2.3.4 Energy losses

The estimated wholesale energy costs resulting from the analysis is referenced to the Queensland Regional Reference Node. These estimates need to be adjusted for

[5] The CER is obligated to publish the official RPP for the 2015 compliance year by 31 March 2015 in accordance with Section 39 of the Renewable Energy (Electricity) Act 2000.

[6] The CER is obligated to publish the official STP for the 2015 compliance year by 31 March 2015 in accordance with subparagraph 40A (3)(a) of the Renewable Energy (Electricity) Act 2000. This is an annual target and does not directly represent liable entities quarterly surrender obligations under the SRES.

transmission and distribution losses associated with transmitting energy from the Regional Reference Node to end-users. Distribution Loss Factors (DLF) for Energex and for the 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 to the estimates to incorporate losses.

The MLF used in the above estimates are based on the 2014-15 MLF published by AEMO. It is expected that AEMO will have published the 2015-16 MLF estimates in time for them to be used in the revised analysis for input to the Final Determination in early 2015.

2.4 Renewable energy policy uncertainty

Renewable energy policy faces considerable uncertainty in the near term.

The Abbott government established an independent panel to review the RET led by Mr Dick Warburton in the first half of 2014. The Panel submitted its final report to the Government in August 2014. The Panel made two recommendations with respect to the LRET:

- Close the LRET scheme to new entrants and grandfather existing participants to 2030
- Set the target annually based on 50 per cent share of electricity demand growth.

In relation to the SRES, the panel recommended closing the scheme or rapidly phasing it out by 2020.

Although the government has not provided a definitive policy position following the release of the Panel's report, it is apparent from recent statements and discussions with other parties that it is willing to consider either a "real 20 per cent" target or a floating annual targets set based on 50 percent of future demand growth.

Changes to the RET legislation face significant hurdles in the Senate given some of the cross-bench Senators have indicated a reluctance to pass any changes. Such a situation may result in the policy uncertainty not being resolved prior to the Final Determination for 2015-16.

Unlike the carbon price, which was largely a binary uncertainty for the 2014-15 tariff year (either included or excluded), there are numerous potential options for modification of the RET. It is therefore difficult to predict the final policy landing for the RET when estimating the tariffs for 2015-16. The uncertainty has had a significant effect on the forward price of LGCs.

As a consequence of the uncertainty we have continued with the current approach which relies on analysing the forward curves for LGCs over time and assumes that retailers supplying non-market customers will acquire LGCs gradually on a portfolio basis over time. In the event that there is definitive shift in the RET policy prior to the Final Determination, the current approach may be modified.

3 Responses to submissions to Interim Consultation Paper

3.1 Introduction

The QCA forwarded to ACIL Allen a total of 13 submissions in response to its Interim Consultation Paper. ACIL Allen reviewed the submissions to identify issues that required our consideration. A summary of the review is shown below. The following sections in this chapter address each of the relevant issues raised in the submissions.

Table 1 **Review of issues raised in submissions in response to Interim Consultation Paper**

Id	Stakeholder	Wholesale energy costs	Contract prices /hedge model	Renewable energy policy costs	NEM fees
1	Australian Sugar Industry Alliance	Yes	No	No	No
2	Canegrowers ISIS Ltd	Yes	No	Yes	No
3	ERAA	Yes	No	No	No
4	Ergon Energy	No	No	No	No
5	Ergon Retail	Yes	No	Yes	No
6	Mark Tranter	No	No	No	No
7	Origin	Yes	Yes	Yes	No
8	Queensland Consumers Association	No	No	No	No
9	Toowoomba Regional Council	No	No	No	No
10	Confidential Submission	No	No	No	No
11	COTA	Yes	No	No	No
12	QCOSS	No	No	No	No
13	ESAA	No	No	No	No

Note: Yes = an issue was raised that required ACIL Allen's consideration
Source: ACIL Allen analysis of QCA supplied documents

3.2 Wholesale energy costs

3.2.1 Overall approach

A number of the submissions (for example, COTA, Ergon Retail) supported the continuation of ACIL Allen's approach for the purposes of consistency.

ERAA, and Origin, both stated that the estimates should be based on the long run marginal cost (LRMC) rather than the market based approach.

ACIL Allen has in previous years discussed and rejected the use of LRMC as a basis for determining the cost of making, producing or supplying customer retail services to customers supplied on notified prices.

ACIL Allen's proposed approach is consistent with the approach used in the advice it provided to the QCA for the 2012-13 Determination and subsequent determinations. This approach was tested in the Supreme Court of Queensland and found to meet the requirements of the Act and Delegation.

3.2.2 'Structural bias' and price shocks

Concerns about the effect of structural biases and potential associated price shocks have been raised by some stakeholders.

Structural bias

Both ERAA and Origin suggest that the lower prices exhibited in the market at present are in part due to 'structural biases', such as growth in solar PV suppressing of wholesale prices and the ramp-up of the LNG trains, and therefore need to be removed from the WEC calculation, otherwise their inclusion will lead to an inaccurate estimate. This in part draws on the AEMC's recommendations on retail price methodology which suggests that 'structural biases' result in futures (or contract) prices becoming inaccurate.

ERAA state on page 2 of their submission that:

> The suppression of wholesale prices due to a number of factors including subsidised solar PV generation may lead to inaccurate wholesale cost factors, particularly when the market normalises in the future. Therefore utilising a retailer's actual cost of supply should provide a more accurate outcome than the QCA's market based approach.

Origin state on page 2 of their submission that:

> Wholesale prices in Queensland are currently at historical lows, which are not an appropriate indicator of future expected prices because of certain structural biases prevalent in Queensland; examples include solar PV, which has had the effect of suppressing wholesale electricity prices, and the ramp up of LNG trains.
>
> While the impact of the ramp up of LNG trains was recognised in QCA's calculation of wholesale costs for 2014-15, the need to account for it confirms the presence of structural biases in Queensland.
>
> Consideration of how best to integrate the impacts of structural biases over a longer horizon is important to promote a stable price path year-on-year. This approach will reduce volatility in notified prices in future years, helping to mitigate the risk of price shocks caused by one-off events.

> This approach is reflected in the AEMC's Final Report on "best practice retail price methodology", where the AEMC recommends that while futures prices should be used as the basis for estimating energy purchase costs:
>
> - if these prices are likely to produce unreliable results (due to either insufficient liquidity in the contracts market; or
> - structural market biases meaning that futures prices may not be a good representation of expected prices),
>
> then a method that approximates the long-term costs of generation should be used to estimate energy purchase costs.

The AEMC state in their report[7] on page 46:

> Any externalities or market structures that create bias can also undermine accuracy in futures prices. This includes uncertainty about future government environmental policies, eg (sic) carbon price, which may reduce the level of trading in the market and/or the length of the contracts that are traded. There may also be subsidies present in the market that distort prices.

Notwithstanding that the AEMC provides a poor definition of 'structural bias' – it considers that these are important where they create bias or undermine the accuracy of futures prices.

The existence and ongoing installation of rooftop solar PV and the likely growth in electricity demand associated with the ramp up in LNG production are not prima facie a structural bias. While there are uncertainties about both of these factors, the extent of these factors and the likely range of effects on wholesale prices is well understood, and in ACIL Allen's view have been incorporated into futures prices. This is evident in the ACIL Allen simulation of the market prices outcomes for 2015-16 (including existing solar installations and expectations about new installations and LNG based increases in electricity demand). The simulated market prices are not dissimilar to observable electricity contract prices, which implies that electricity contract markets are appropriately accounting for any structural risks.

This issue is even less of a concern given the analysis for the Draft Determination is concerned with one year into the future as opposed to projecting long term retail costs which would be more susceptible to shifts in government policy, consumer preferences and technology.

Price shocks

At the end of page 2 of their submission, Origin Energy also argues for consideration of changes to the market based approach in order to "mitigate the risk of price shocks caused by one-off events". Origin consider that it is "important to promote a stable price path year-on-year".

ACIL Allen do not agree with Origin Energy with respect to the importance of the stability of prices year on year.

First, the objective of stability of prices year-on-year is inconsistent with Queensland Government policy of annually reviewing the actual costs of making, producing or supplying

[7] http://www.aemc.gov.au/getattachment/c03a2033-192c-440a-a83b-75f92644212c/Final-Report.aspx

customer retail services to non-market customers. Indeed, the TOR instructs ACIL Allen to estimate the actual costs of supplying customers on notified prices specifically for 2015-16.

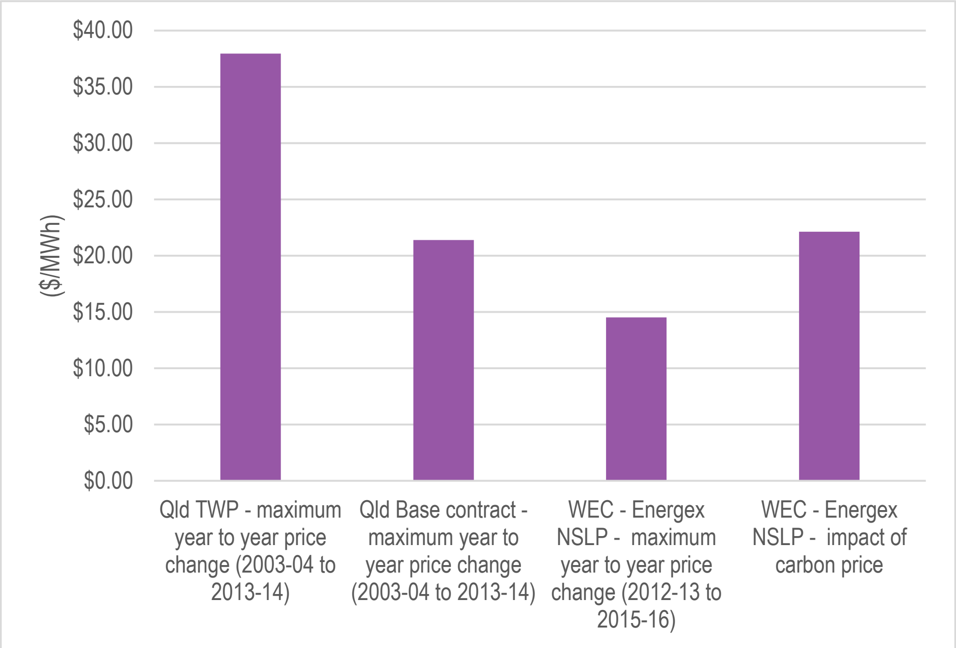
Second, in ACIL Allen's view, from an efficiency perspective, it is much more important that prices are cost reflective; i.e. the prices reflect the actual costs of making, producing or supplying customer retail services to non-market customers for the tariff year 1 July 2015 to 30 June 2016. In ACIL Allen's experience, seeking to smooth prices over time is likely to lead to customers paying higher overall prices, in part because in smoothing out future uncertainties a risk premium is included. It is also the case that "smoothed prices" are less likely to respond to downward drivers than upward drivers.

Notwithstanding the above comments, the graphs presented in Section 4.2 clearly show that the hedging approach removes a large degree of weather and plant availability driven price volatility exhibited in the wholesale spot price simulations. Further, Figure 1 below compares the change in annual Queensland prices in the spot and contact markets over the past 11 years with changes in the WEC over the past four determinations. The key points of this graph are:

- ACIL Allen agrees that the market based approach should result in changes in costs being reflected in changes in prices – importantly in both directions, depending on changes in the state of the market.
- The maximum year on year annual price increase in the spot market over the past 11 years is about $37/MWh.
- This compares with a maximum change of about $22/MWh in the contract market – demonstrating that hedging smooths price changes to some degree.
- The maximum year on year movement in WEC is about $15/MWh – less than the spot price and contract price changes observed in the past.
- But more importantly, the increase in WEC due to a carbon price is about $22/MWh – which is about the same as the greatest price change in the contract prices. That is, if a price stability objective had been included prior to the past four determinations, there would still have been, as described by Origin, a price shock in the WEC when the carbon price was introduced in 2012-13, and this price shock would have had an order of magnitude very similar to the price shocks observed in WECs based on the market based approach when excluding the effect of a carbon price.
- Similarly a price stability objective may have partially or fully inhibited the removal of the carbon price in 2014-15.

ACIL Allen therefore is comfortable with a continuation of the current market based approach. In an economically efficient market, such as the NEM, the market prices over time reflect the cost of efficient supply

Figure 1 **Year on year changes to wholesale electricity prices ($/MWh) in Queensland**



Source: ACIL Allen analysis of AEMO data and ASX-Energy data

3.2.3 WEC levels

A number of submissions commented on the overall level of the energy component of retail prices. For example, the Australian Sugar Industry Alliance stated in its submission that the tariff levels for millers were too high and comparable to prices paid by households.

These particular submissions are focussed on the tariff structure, and associated price level, rather than the methodology that we have undertaken to derive the pricing level. ACIL Allen's role in the determination process is to estimate energy costs for a given set of demand profiles, not to provide advice on appropriate tariff structures.

3.2.4 Escalation of WEC

Canegrowers ISIS suggested on page three of their submission that

> Ergon's energy price should be based on Energex's energy price from the previous year plus CPI.

Wholesale electricity prices, and their components, do not necessarily escalate from one year to the next at a rate equal to CPI. The NEM is a dynamic market, and wholesale electricity prices in a given year are a function of the supply-demand balance of the market as well as the input costs for generators, such as fuel prices, which in turn are determined by markets external to the electricity market (some of which are subject to international prices and exchange rates).

The approach adopted by ACIL Allen for this determination and previous determinations is to estimate the WEC based on simulating the market taking into account market conditions and the costs of procuring electricity hedges. In some years this approach may result in an increase in prices more than CPI, and in the case of this year, an increase in prices less than CPI, or even a decline in price.

Taking the prices from the previous determination and then applying CPI each year into the future runs the risk of future tariffs not reflecting the actual cost of procuring energy from the NEM.

3.2.5 Correlation of demand and temperature

Origin, as in previous years, raised the issue of ACIL Allen's demand simulation and its approach to extreme temperatures (on page 3 of their submission):

> In previous pricing decisions, the QCA has accepted the position put forward by ACIL that above certain temperatures, the relationship between temperature and peak demand weakens such that demand tends to reach a limit. However, Origin considers that to date, the nature of this relationship has not been adequately established since it is not extrapolated, but assumed. The result is that this approach arbitrarily caps the relationship between outlying temperature and demand, thereby reducing the efficacy of using actual temperature records. For these reasons, the QCA should provide clarity regarding how these limits are captured in its modelling.

ACIL Allen is of the opinion that it has adequately considered the relationship between demand and temperature. Further this was demonstrated in our report for the Final Determination of the 2014-15 tariffs which included analysis of demand during the extreme temperature days of January 2014 which showed clearly a lower slope for demand during periods of consecutive extreme hot days (refer to section 2.2, starting on page 12 of the ACIL Allen report for the 2014-15 Final Determination).

3.3 Renewable energy policy costs

Canegrowers ISIS suggested on page 3 of their submission that allowances such as the RET have been used in earlier determinations to artificially inflate notified prices and that the RET allowance (amongst others) should not be included in the notified prices for Ergon's small business customers.

Under the RET, liable entities (typically electricity retailers) have a legal obligation to buy and surrender LGCs and STCs to the Clean Energy Regulator on an annual basis.

Ergon Retail states on page four of their submission:

> We have noticed that the recent RET review and speculation on the future of the RET scheme has reduced liquidity in the Large-scale Generation Certificate (LGC) market. It has had a noticeable impact on prices for LGCs and therefore we caution that this may distort the output of modelling undertaken by QCA's consultants and impact the 2015-16 LRET allowance.
>
> If the future of the RET schemes becomes clearer, particularly if a bipartisan position on the scheme emerges, there could be a step-change in the price of certificates.
>
> …, we would encourage the QCA to source the most up-to-date publicly available data to support any decisions in this area, and caution against using historical prices as a predictor of the compliance cost to retailers … Due to the risk of the RET scheme being abolished, many

> retailers would have delayed purchasing LGCs beyond the February 2015 surrender requirements. Actual market prices, after the changes to the RET schemes are known, would be a much better indicator of actual compliance costs.

Origin Energy suggest on page three of their submission that the QCA needs to take into account the substantial reduction in liquidity for trading of LGCs due to the current policy uncertainty:

> Given the lack of liquidity, it is not reasonable to suggest that a retailer could meet its LRET obligations based on buying LGCs in the market alone; there are insufficient volumes available. Supplementary supply sources like retailer-owned renewable plant or PPAs are required to make up the difference. As a result, current LGC market prices do not reflect the actual cost of retailers meeting their RET liabilities. Origin considers that in this context, a robust and transparent assessment of LRMC is a more reliable and cost reflective approach for determining RET costs.

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 observable pricing are the spot and forward contracts transacted through brokers.

While ACIL Allen recognises that the recent RET review has created uncertainty around the future of the scheme and has temporarily dampened LGC prices, 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 gives appropriate weight to recent market trading opportunities and allows new information to be included when it becomes available to the market.

ACIL Allen has taken the average of the AFMA LGC prices for 2015 and 2016 based on the past two years of data, and therefore this estimate reflects liquidity over two years rather than only over data. In addition, the AFMA LGC price data being relied upon is survey based, including, amongst others, nine retailer respondents. The data includes bids, asks and mid-points excluding outliers. The mid-points excluding outliers reflect the market consensus view of the price of LGCs at the time of surveying. Although the AFMA data does not provide a measure of trades, our analysis of the AFMA data suggests that the number of respondents has not decreased noticeably in recent months. Further, our analysis of the data suggests that the current level of agreement amongst respondents is no lower now than it was, say, two years ago.

As stated above, ACIL Allen believes that observable market prices provide an appropriate indicator of current prices compared with any modelled outcomes. ACIL Allen on page 27 in its report for the 2014-15 Final Determination[8] addressed the issue of using LRMC in detail. We acknowledge the uncertainty due to the RET review, but there are a large number of other uncertainties which influence the LGC price – such as the level of future black energy price outcomes over the life of the LRET (not just in 2015-16), trends in capital costs of new build plant, the potential for inclusion of a carbon price in the future. Each of these uncertainties have been, in effect, factored into the futures prices.

[8] http://www.qca.org.au/getattachment/9be567a8-92e2-4d53-85f0-3781e4f8662f/ACIL-Allen-Final-Report-Estimated-Energy-Costs-for.aspx

4 Estimation of energy costs

4.1 Introduction

In this section we apply the methodology and summarise the estimates of each component of the total energy costs for each of the tariff classes for 2015-16.

4.2 Estimation of WEC

4.2.1 Estimating contract prices

Contract prices for Queensland were estimated using the trade-weighted average of ASX Energy daily settlement prices since the contract was listed up until 30 October 2014.

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) – 2015-16**

	Q3 2015	Q4 2015	Q1 2016	Q2 2016
Base	$41.11	$45.77	$56.85	$41.95
Peak	$47.00	$59.60	$81.00	$48.00
Cap	$3.81	$6.99	$13.67	$3.83

Source: ACIL Allen analysis using ASX Energy data up to 30 October 2014

Contract prices for 2015-16 are around the same level as contract prices for 2014-15. This is likely to be due to the market revising downwards the expected demand growth across the NEM, driven by delays in the commencement of LNG exports in Queensland and revising upwards the penetration of rooftop solar PV in most regions.

The following charts show daily settlement prices and trade volumes for ASX Energy quarterly base futures, peak futures and cap contracts up to 30 October 2014.

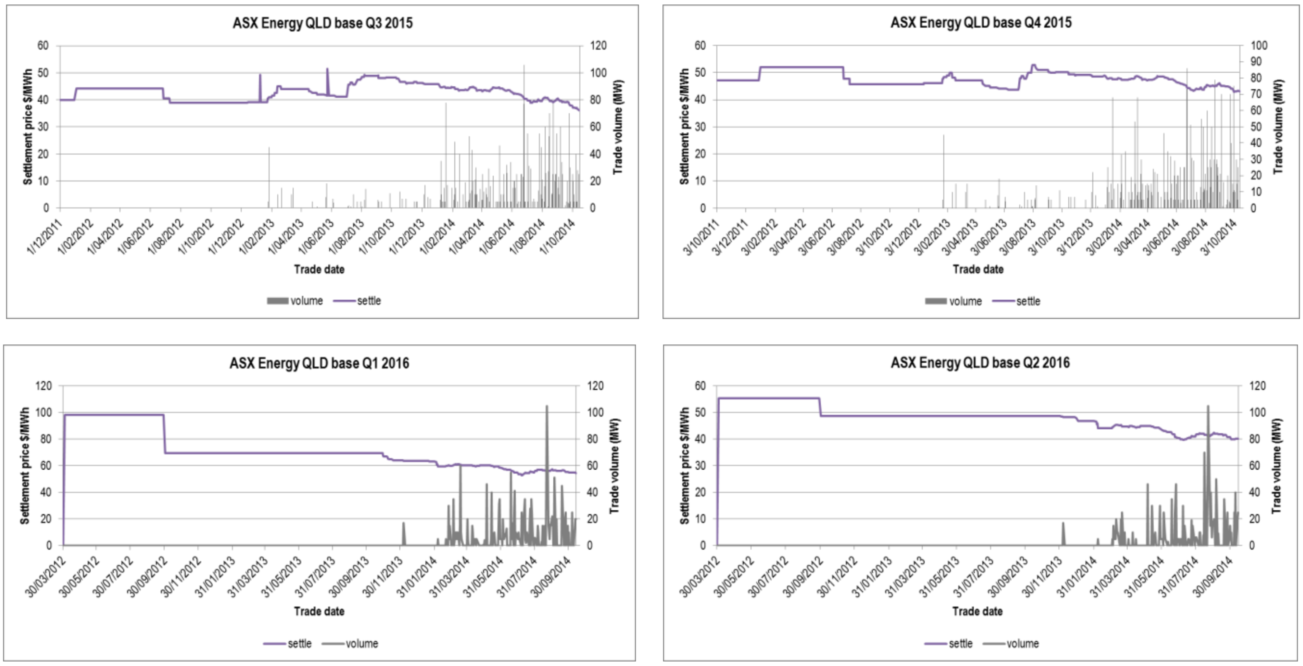
Base futures have traded strongly in 2015, with total volumes between 2,915 MW (Q4 2015) and 3,058 MW (Q3 2015). Volumes are lower in 2016, between 1,304MW (Q2 2016) and 1,521MW (Q1 2016). However, these volumes are consistent with the 2014-15 equivalent quarterly futures as at 30 October 2013 for the previous 2014-15 Draft Determination.

Peak futures have lower trade volumes of 5 MW (Q3 2014) and no trade volume in Q4 2015 and 2016, 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 76 MW (Q2 2016) to 937MW (Q1 2016).

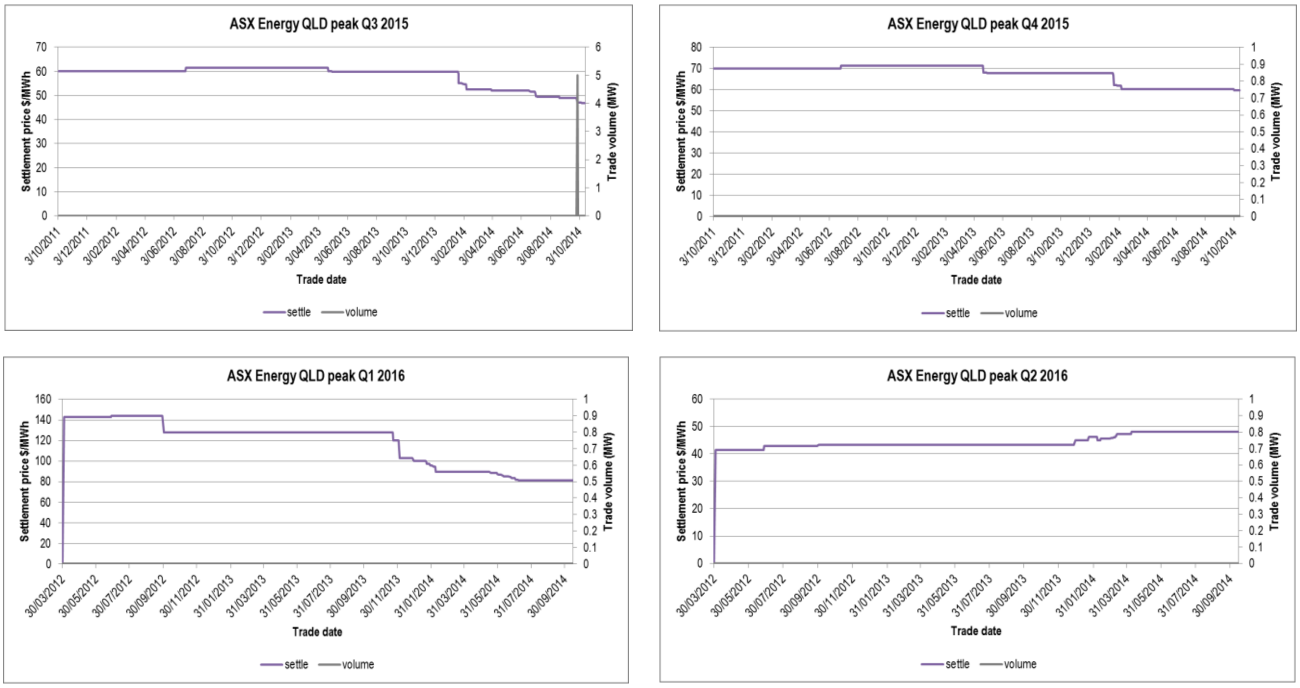
Whilst trade volumes for peak futures appear low, they are, in our experience, at normal levels for this time of year. We expect trade volumes for peak futures to begin to increase during early 2015 closer to the commencement of the contract terms.

Figure 2 **Time series of trade volume and price – ASX Energy QLD BASE futures for Q3 2015, Q4 2015, Q1 2016 and Q2 2016**



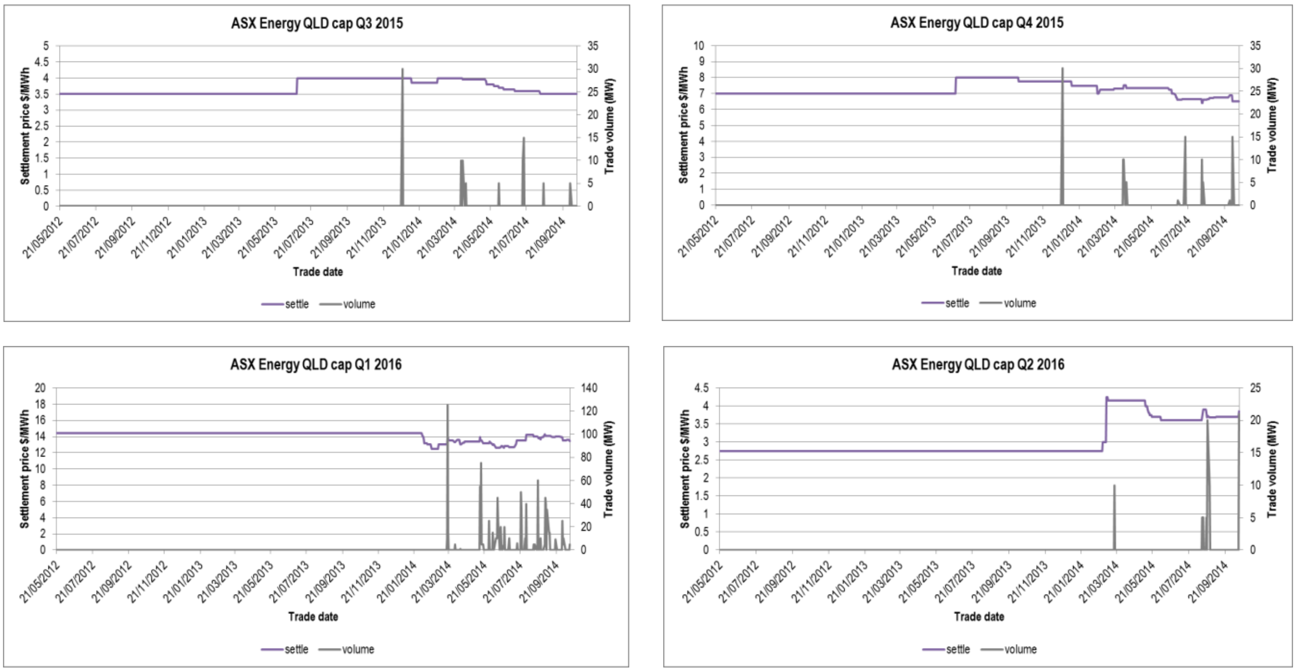
Data Source: ASX Energy data up to 30 October 2014.

Figure 3 **Time series of trade volume and price – ASX Energy QLD PEAK futures for Q3 2015, Q4 2015, Q1 2016 and Q2 2016**



Data Source: ASX Energy data up to 30 October 2014.

Figure 4 **Time series of trade volume and price – ASX Energy QLD $300 CAP contracts for Q3 2015, Q4 2015, Q1 2016 and Q2 2016**



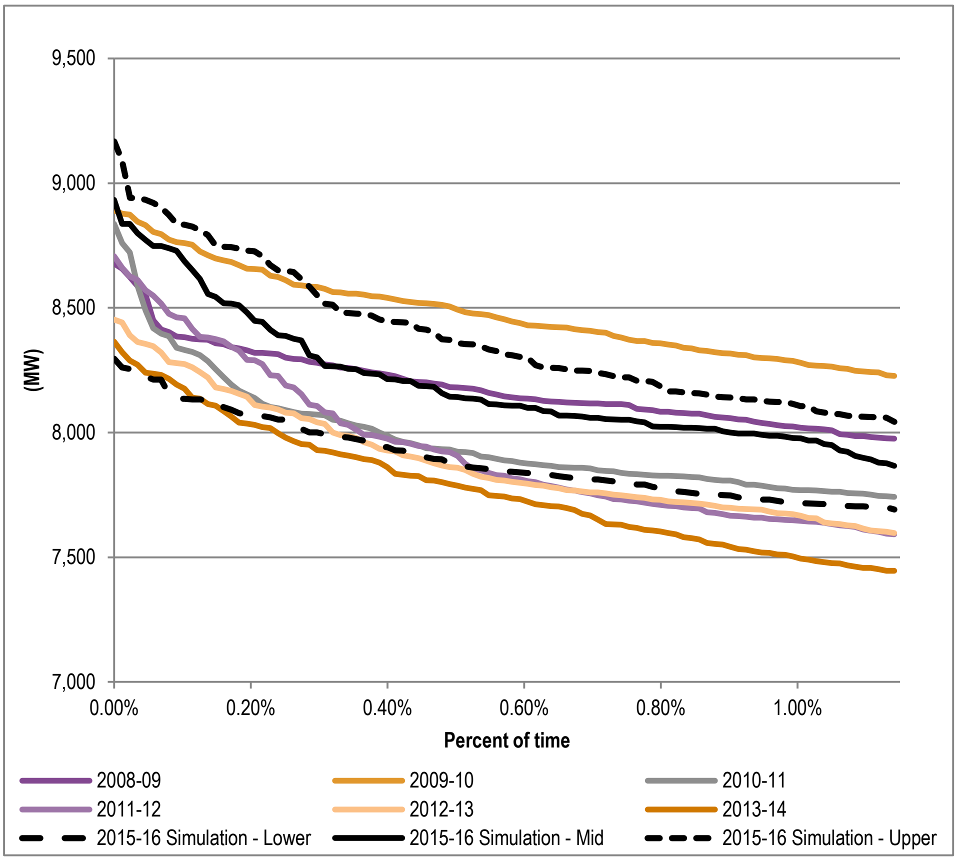
Data Source: ASX Energy data up to, and including 30 October 2014.

4.2.2 Estimating wholesale spot prices

PowerMark was run to estimate the hourly pool prices for 2015-16 for 484 simulations by (44 demand and 11 outage sets).

Figure 5 shows the upper 100 hour segment of the demand duration curves for three of the 44 simulated Queensland demand sets resulting from the methodology along with the historical demands since 2008-09. The three simulated demand sets represent the upper, lower and middle of the range of demand duration curves across all 44 simulated sets. It can be seen that the demand duration curves of the simulated demand sets for 2015-16 not only envelope the recent historic demand duration curves, but demonstrate that the difference between the maximum and minimum of the envelope averages around 500MW 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 as discussed further in this section.

Figure 5 **Top 100 hourly demands – Queensland**



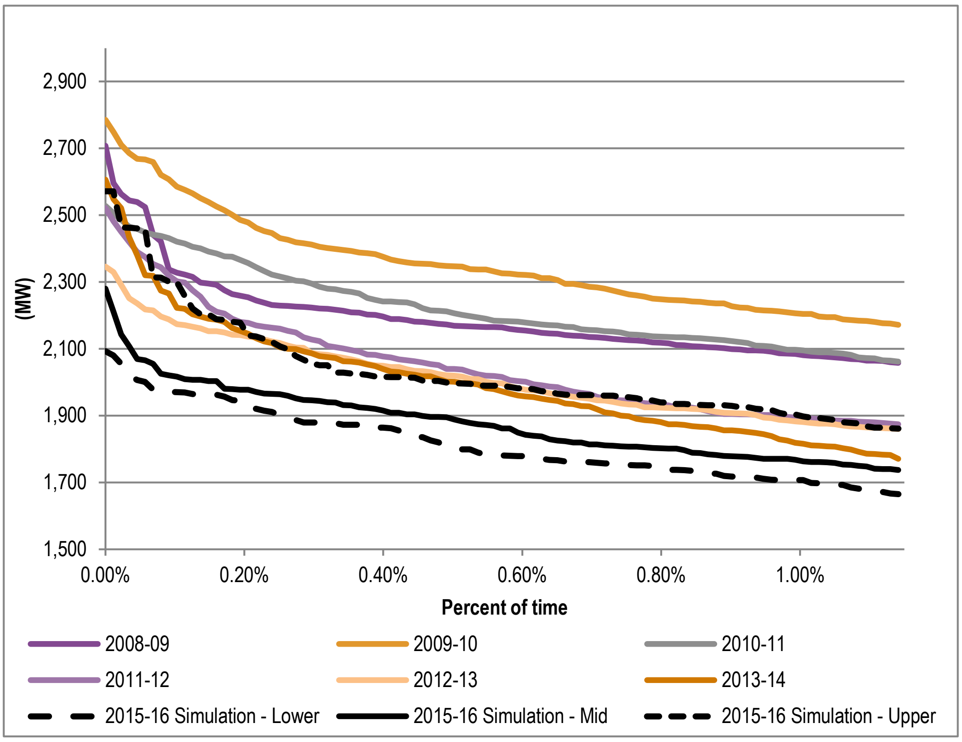
Note: Data for 2008-09 to 2013-14 includes top 200 half hourly demands
Source: ACIL Allen analysis and AEMO data

Figure 6 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. This variation results in the annual load factor[9] ranging between 29% and 37% compared with a range of 40% to 33% for the actual NSLP between 2008-09 and 2013-14. There has been a lowering in the load factor in the NSLPs in recent years due to an increase in penetration of rooftop solar PV panels – the increased penetration no longer reduces the peak demand (since the peak demand occurs between 6:30pm and 8:30pm) but continues to reduce the average metered demand.

All other things equal, the increased peakiness of the load, which still requires to be hedged, is likely to result in a larger degree of over hedging across the general day-time peak periods of the day, resulting in a larger degree of over hedging, which means hedging costs would increase.

[9] The load factor is a measure of the peakiness in the half hourly load profile across a given period of time. The annual load factor is the average of the half hourly loads for the given year divided by the maximum of the half hourly loads for that same given year.

Figure 6 **Top 100 hourly demands – Energex NSLP**

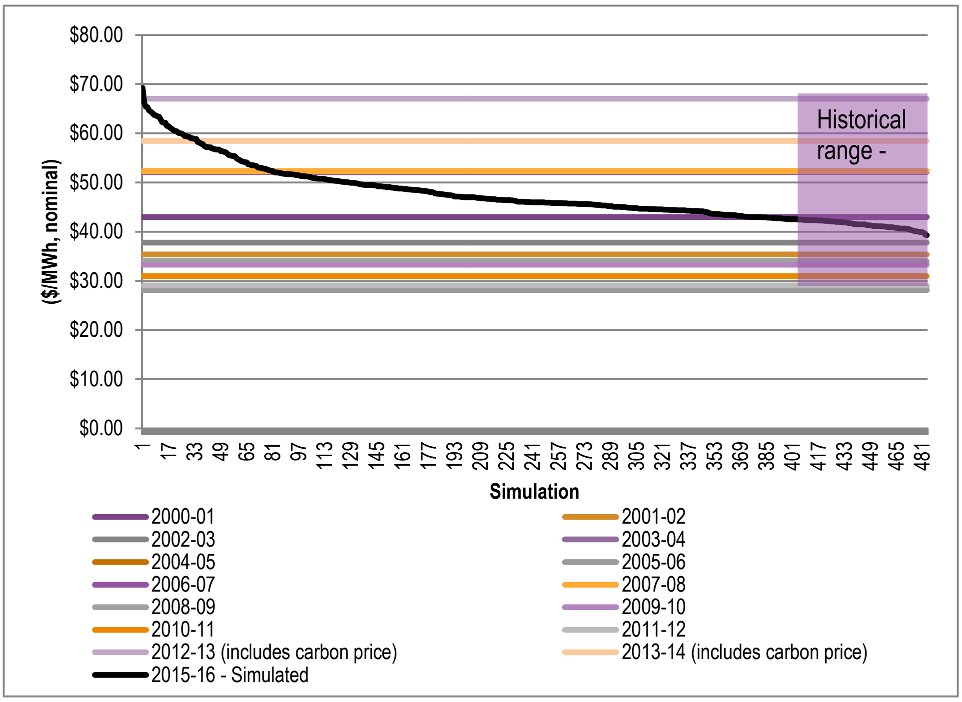


Note: Data for 2008-09 to 2013-14 includes top 200 half hourly demands
Source: ACIL Allen analysis and AEMO data

The annual time weighted pool prices (TWP) for Queensland from the 484 simulations range from a low of $39.24/MWh to a high of $69.23/MWh. This compares with the lowest recorded Queensland TWP in the last 14 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 7 compares the Queensland TWP for the 484 simulations for 2015-16 with the Queensland TWPs from the past 14 years. Although there have been changes to both the supply and demand side of the market, the graph clearly shows that the simulations cover a wide range in potential prices for 2015-16 when compared with the past 14 years of history. The lower part of the distribution of simulated outcomes sits above some of the actual outcomes (particularly of the earlier years of the market), but by 2015-16 gas prices are projected to be around $9/GJ, compared with $3 - $4/GJ in recent years, and the operating costs of coal plant have increased since the market's inception, and these, coupled with demand growth due to the LNG terminals, have the effect of influencing an increase in the lower bound on annual price outcomes. ACIL Allen is satisfied that in an aggregate sense the distribution of the 484 simulations for 2015-16 cover an adequately wide range of possible annual pool price outcomes.

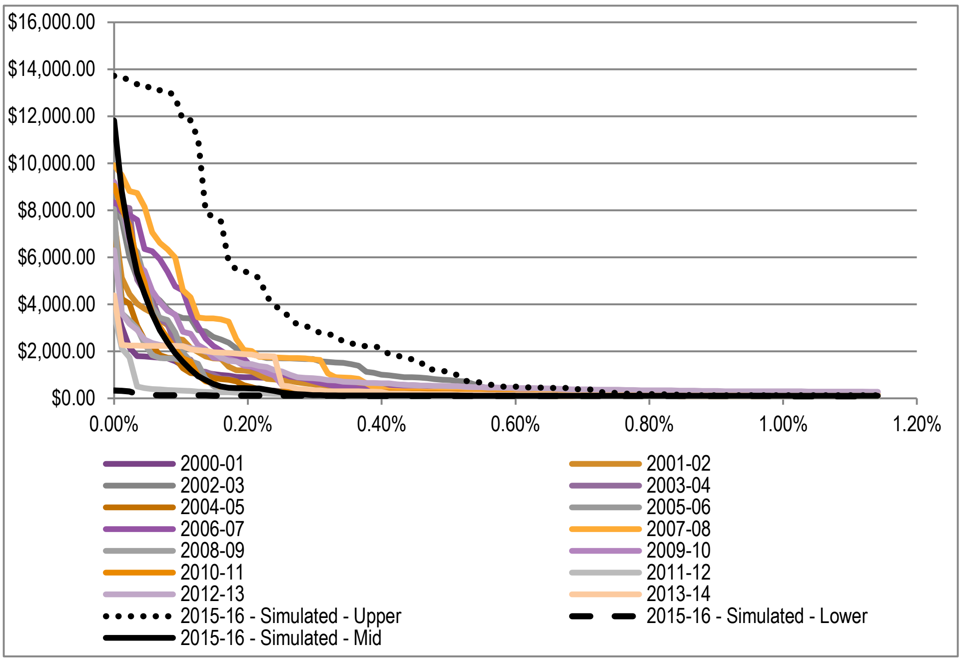
Figure 7 **Annual TWP for Queensland for 484 simulations for 2015-16 compared with actual annual outcomes in past years**



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 hourly prices from the simulations also more than adequately covers the historical spread of spot prices. The comparison is illustrated in Figure 8 which clearly demonstrates that range of upper 1% of prices from the 484 simulations for 2015-16 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.

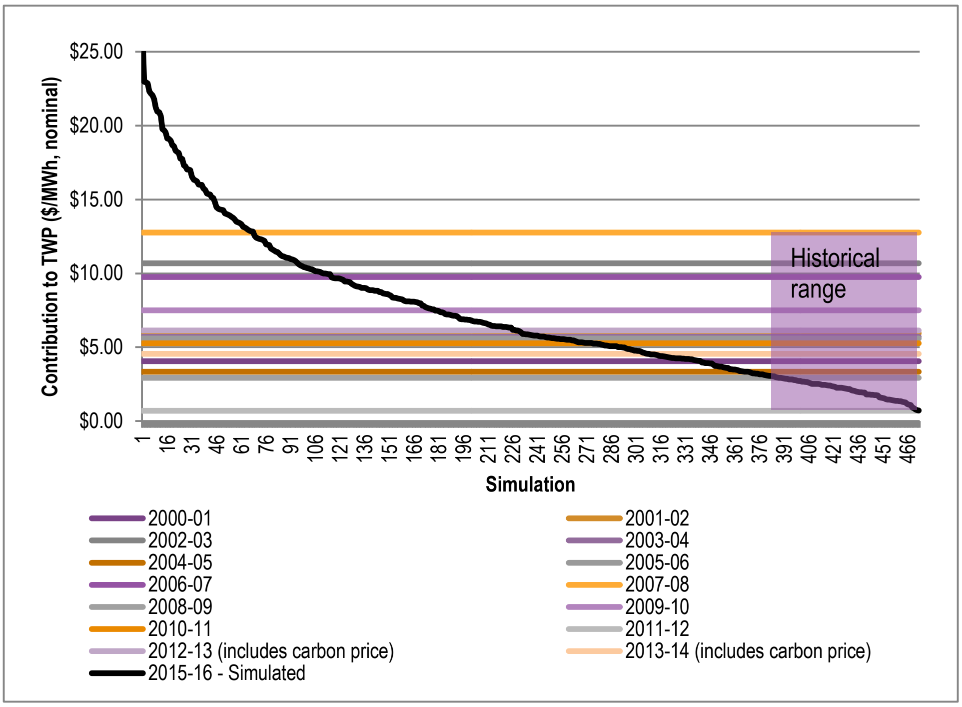
Figure 8 **Comparison of upper tail of hourly price duration curve for Queensland for 484 simulations for 2015-16 compared with actual outcomes in past years**



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

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 484 simulations. The range in annual average contribution to the TWP, of hourly prices above $300/MWh, for the 484 simulations is consistent with those recorded in history as shown in Figure 9.

Figure 9 **Annual average contribution to the TWP by prices above $300/MWh in the modelled simulations and recorded in the past**



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

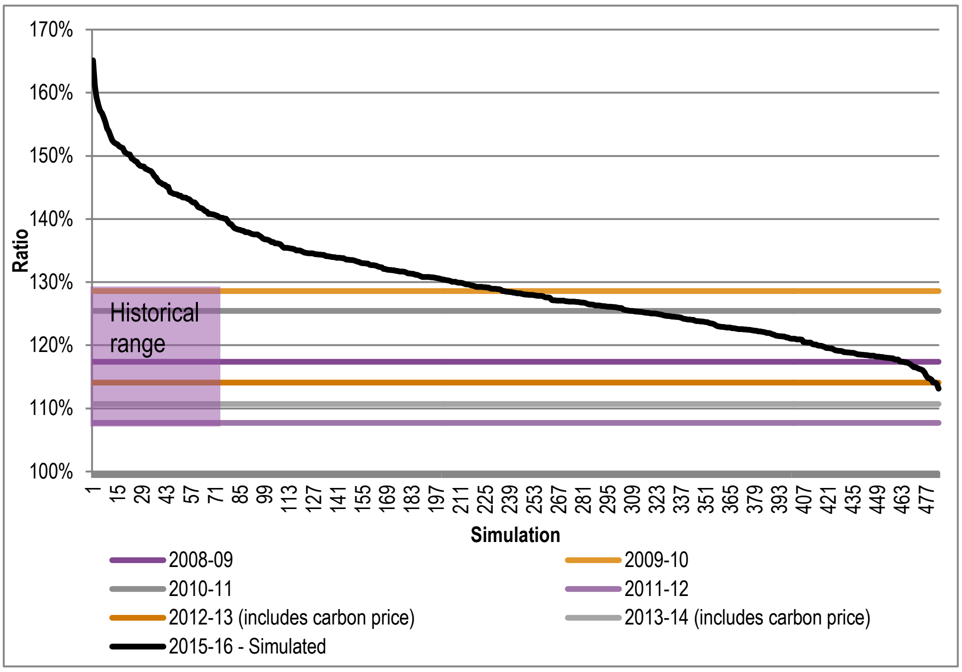
Submissions to the 2013-14 and 2014-15 determinations suggested that the NSLP peak demand is too low which in turn is presumed to lead to a lower cost to supply the NSLP. However, the maximum demand of the NSLP is not in isolation a critical feature in determining the cost of supply. The shape of the NSLP demand trace and its relationship to the shape of the Queensland demand/price traces is a 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 demand weighted price (DWP) for the Energex NSLP with the Queensland TWP. Figure 10 shows that, for the past six 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 484 simulations for 2015-16, this percentage varies from 113% to 165%. These results more than adequately cover the historical range.

The comparison with actual outcomes over the past five years in Figure 10 demonstrates that the relationship between the Energex NSLP demand and Queensland pool prices in the

484 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 2015-16. It also provides a sound cross check on the shape of the NSLP demand and its relationship with the Queensland demand.

Figure 10 **Annual DWP for Energex NSLP as percentage of annual TWP for Queensland for 484 simulations for 2015-16 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 484 simulations cover the range of expected price outcomes for 2015-16 both on average and in the upper tail. These comparisons clearly show that the 44 simulated demand traces combined with the 11 plant outage scenarios provide a sound basis for modelling the expected future outcomes for 2015-16.

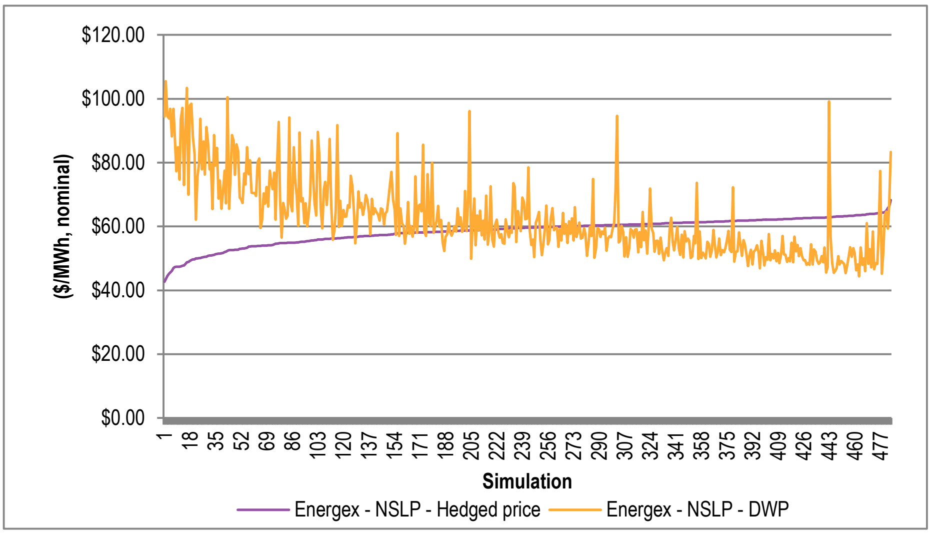
4.2.3 Applying the hedge model

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 estimates provided in Section 4.2.1.

As hedge benefits are inversely related to pool prices, simulations with higher demand weighted pool prices usually produce lower hedged prices. Figure 11 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.

Figure 11 **Annual hedged price and DWP for Energex NSLP for the 484 simulations ($/MWh)**



Source: ACIL Allen modelling

Contract volumes continues to be calculated for each settlement class for each quarter as follows:

— The base contract volume is set to equal the 80th percentile of the off-peak period hourly demands across all 44 demand sets for the quarter.

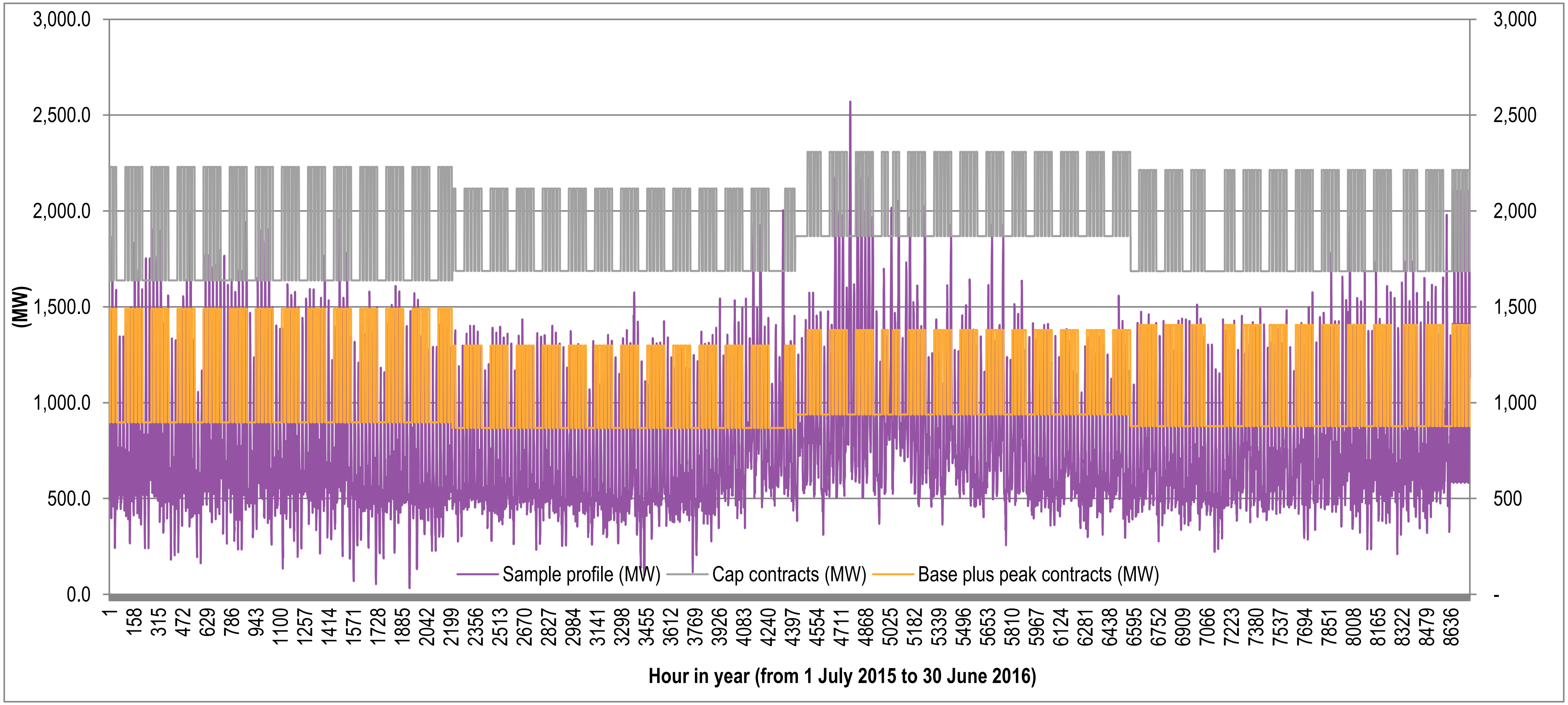
— The peak period contract volume is set to equal the 90th percentile of the peak period hourly demands across all 44 demand sets for the quarter.

— The cap contract volume is set at 105 per cent of the median of the annual peak demands across the 44 demand sets minus the base and peak contract volumes.

In other words, the same hourly hedge volumes (in MW terms) apply to each of the 44 demand sets for a given settlement class, and hence to each of the 484 simulations. To be clear, we are not altering the hedge volume (in MW terms) on an ex-post basis for each of the 44 demand sets. Therefore, the approach we use results in a hedging strategy that does not rely on perfect foresight but relies on an expectation of the distribution of hourly demands across a range of temperature outcomes.

Once established, these contract volumes are then fixed across all 484 simulations when calculating the wholesale energy cost. The contract volumes used are shown in Figure 12.

Figure 12 **Contract volumes used in hedge modelling of 484 simulations for 2015-16 for Energex NSLP**



Source: ACIL Allen

4.2.4 Summary of estimated WEC

After applying the hedge model, the WEC was taken as the 95th percentile of the distribution containing 484 annual hedged prices. ACIL Allen's estimate of the WEC for each tariff class for the 2015-16 Draft Determination are shown in Table 3.

The estimated WECs for 2015-16 generally increase or decrease by less than two percent compared with the final determination for 2014-15. To put these changes into context, the overall movement in the WECs is less than a typical CPI of 2.5 percent. The WEC for control tariff 31 increases by just over four percent, compared with the final determination for 2014-15.

The reason the WECs for some tariffs increase and others decrease relates to the nature of the shape of the corresponding load profile and how that shape has changed between the 2014-15 Final Determination and the 2015-16 Draft Determination. In broad terms, although the modelled spot prices for 2015-16 are very similar to those of the 2014-15 tariff review on an annual basis, their shape across the day is slightly different. Compared with 2014-15, the increase in solar PV installations tends to decrease price volatility during the day-time peak periods in the 2015-16 simulation. During the off-peak periods, prices are more influenced by the underlying costs of the power stations (which are dominated by fuel costs) rather than their bidding behaviour. Between 2014-15 and 2015-16 the assumed fuel prices increase by about four percent on average – with coal prices increasing by about 2.5 percent on average and gas prices increasing by well above CPI due to the increased demand for gas from the LNG projects. In other words, compared with 2014-15, the simulated prices for 2015-16 decrease slightly during the day time and increase slightly during the night.

Therefore, the controlled load of tariff 31, which is dominated by hot water heating occurring overnight, is estimated to have a WEC in 2015-16 higher than the 2014-15 WEC. Conversely, the controlled load of tariff 33 is more skewed to day time use (for example, pool filters), and consequently the estimated WEC for 2015-16 is slightly less than the WEC of 2014-15.

The load profiles of the Energex and Ergon NSLPs are a mixture of day time and night time use and therefore the change in their WECs from 2014-15 to 2015-16 tends to be a mixture of the increasing prices across the off-peak periods and the slight decrease in prices across the peak periods – the combined changes of which cancel out to some degree thus resulting in a change in WEC less than CPI.

The Energex and Ergon NSLP WECs increase and decrease respectively compared with the 2014-15 Final Determination. At face value this may seem implausible. In previous tariff reviews, the overall increase in spot and contract prices has been sufficient to result in increases in the WECs for these two load profiles. However, their WECs did not increase by the exact same percentage, as mentioned earlier, due to their different load shapes. But nonetheless, they both increased. For the current review the change in spot and contract prices, relative to the 2014-15 Final Determination, is subtle and this has resulted in small changes in the WECs – some positive and some negative. The Ergon NSLP WEC has decreased slightly mainly due to a net benefit from lower price volatility across the day time. The overall annual energy for the Ergon and Energex NSLPs is roughly similar (with the Ergon NSLP about four percent lower than the Energex NSLP) – but about 70 percent of rooftop solar PVs installed in Queensland are in the Energex network – this results in the two NSLPs having very different shapes across the day time period. The increase in solar PV installs in Energex (and Ergon) has contributed to a lower price volatility during the day time – but since the demand profile for the Energex NSLP is being noticeably reduced during the day time, this removes some of the day time price benefit on an annual demand weighted basis. Whereas, the Ergon NSLP has not experienced the same degree of demand reduction during the day time and hence benefits slightly on a demand weighted basis. It is also worth noting that the demand profile of tariff 33 is not influenced by installations of solar PV, and so it tends to benefit from the reduction in price volatility.

Table 3 **Estimated WEC ($/MWh, nominal) for 2015-16 at the Queensland reference node**

Settlement class	2015-16 – Draft Determination	2014-15 – Final Determination
Energex - NSLP - residential and small business	$63.42	$62.26
Energex - Control tariff 9000 (31)	$38.56	$36.60
Energex - Control tariff 9100 (33)	$49.72	$50.71
Energex - NSLP - unmetered supply	$63.42	$62.26
Ergon Energy - NSLP - SAC HV, CAC and ICC	$55.60	$55.75
Ergon Energy - NSLP - SAC demand and street lighting	$55.60	$55.75

Source: ACIL Allen analysis

4.3 Estimation of renewable energy policy costs

The RET scheme consists of two elements – the LRET and the SRES. Liable parties (i.e. all electricity retailers[10]) 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[11]
- LRET targets for 2015 and 2016 of 18,850 GWh and 21,431 GWh respectively, as published by the Clean Energy Regulator (CER)
- Estimated Renewable Power Percentages (RPPs)[12] for 2015 and 2016 of 10.74 per cent and 12.43 per cent, respectively
- CER's non-binding estimates for Small-scale Technology Percentage (STP) of 10.10 and 10.32 per cent for 2015 and 2016, respectively[13]
- CER clearing house price for 2015 and 2016 for Small-scale Technology Certificates (STCs) of $40/MWh.

4.3.1 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,

10 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.

11 AFMA data includes weekly prices up to and including 30 October 2014.

12 RPP values were estimated using liable electricity acquisitions implied in the non-binding STPs as published by CER.

13 The 2015 and 2016 non-binding STP estimates are based on the modelling prepared for the 2014 STP. The binding STP estimate for 2015 will be published by 31 March 2015.

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.

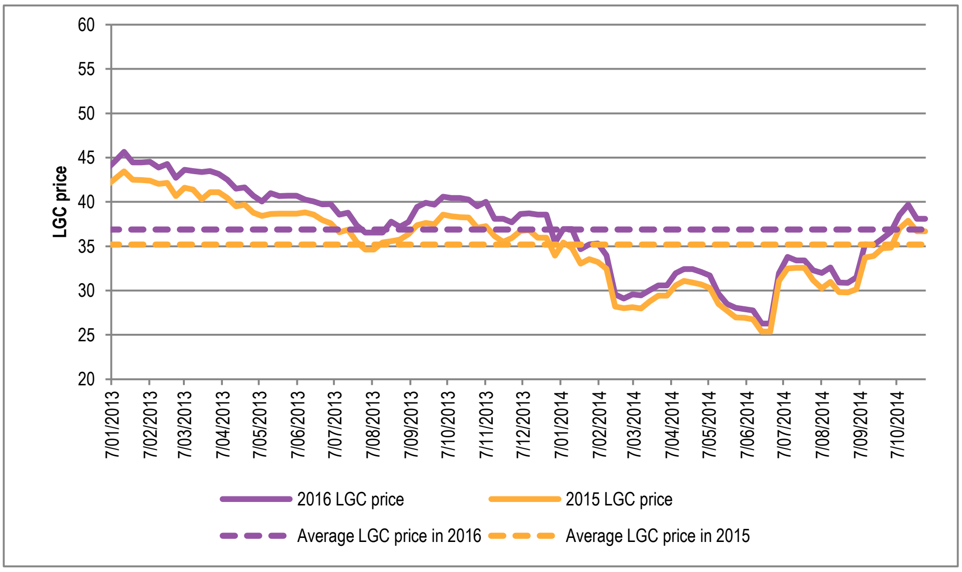
The estimated cost of compliance with the LRET scheme is derived by applying the RPP to the determined LGC price to establish the cost per MWh of liable energy supplied to customers. Since the cost is expressed as a cost per MWh, it is applicable across all retail tariffs.

ACIL Allen has estimated the average LGC price using forward looking weekly market prices for LGCs published by the Australian Financial Markets Association (AFMA) [14].

The LGC price used in assessing the cost of the scheme for 2015-16 is found by averaging the forward prices for 2015 and 2016 during the two years prior to the commencement of 2015 and 2016. This assumes that LGC coverage is built up over a two year period (see Figure 13). The average LGC prices calculated from the AFMA data are $35.19/MWh for 2015 and $36.90/MWh for 2016**.**

The estimate of the LGC price will be influenced by the RET review as shown in the graph below. However, it was possible to purchase LGCs during the period of the review at the discounted prices. Although attempting to remove the effects of the review is an option, such a change to methodology would then require consideration of other risks; their identification and quantification.

Figure 13 **LGC futures prices for 2015 and 2016 (nominal $/LGC)**



Source: AFMA and ACIL Allen analysis

RPP values were estimated using reduced relevant acquisitions implied in the non-binding STPs published by CER.

Key elements of the RPP estimation are shown in Table 4.

[14] 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.

Table 4 **Estimating the RPP**

	2015	2016
Non-binding STP (CER)	10.10%	10.32%
Projected STCs (CER)	17,728,000	17,790,000
Implied reduced relevant acquisitions [a]	175,524,752	172,383,721
LRET target	18,850,000	21,431,000
Estimated RPP using implied reduced relevant acquisitions	10.74%	12.43%

[a] Implied reduced relevant acquisitions was found by dividing projected STCs by the non-binding STP.
Source: CER and ACIL Allen analysis

ACIL Allen calculates the cost of complying with the LRET in 2015 and 2016 by multiplying the RPPs in 2015 and 2016 by the average LGC prices in 2015 and 2016, respectively. The cost of complying with the LRET in 2015-16 was found by averaging the calendar estimates.

Therefore, ACIL Allen estimates the cost of complying with the LRET scheme to be $4.18/MWh in 2015-16 as shown in Table 5.

Table 5 **Estimated cost of LRET – 2015-16**

	2015	2016	Cost of LRET 2015-16
RPP %	10.74%	12.43%	
Average LGC price ($/LGC, nominal)	$35.19	$36.90	
Cost of LRET ($/MWh, nominal)	$3.78	$4.59	$4.18

Source: CER, AFMA, ACIL Allen analysis

4.3.2 SRES

The cost of SRES for calendar years 2015 and 2016 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 2015-16.

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

- 10.10 per cent for 2015 (equivalent to 17.73 million STCs as a proportion of total estimated liable electricity for the 2015 year)
- 10.32 per cent for 2016 (equivalent to 17.79 million STCs as a proportion of total estimated liable electricity for the 2016 year).

ACIL Allen estimates the cost of complying with SRES to be $4.08/MWh in 2015-16 as set out in Table 6.

Table 6 **Estimated cost of SRES – 2015-16**

	2015	2016	Cost of SRES 2015-16
Non-binding STP %	10.10%	10.32%	
STC clearing house price ($/STC, nominal)	$40.00	$40.00	
Cost of SRES ($/MWh, nominal)	$4.04	$4.13	$4.08

Source: CER, ACIL Allen analysis

4.3.3 Summary of estimated LRET and SRES costs

Adding these component costs gives a total other cost requirement as set out in Table 11.

Table 7 **Total renewable energy policy costs ($/MWh) – 2015-16**

Cost category	Cost ($/MWh)
LRET	$4.18
SRES	$4.08
Total	$8.26

Source: ACIL Allen analysis

4.4 Estimation of other energy costs

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

- Market fees and charges including:
  - NEM management fees
  - Ancillary services costs
- Pool and hedging prudential costs.

4.4.1 NEM management fees

NEM management fees are payable by retailers to AEMO to cover operational expenditure, costs associated with full retail contestability (FRC) and costs associated with the National Transmission Planner.

Based on projected fees in AEMO's *Electricity Final Budget & Fees 2014-15*, the total fee for 2015-16 is $0.50/MWh. The breakdown of NEM management fees is shown in Table 8.

Table 8 **NEM management fees ($/MWh) – 2015-16**

Cost category	Fees ($/MWh)
NEM fees	$0.41
FRC - electricity	$0.06
National Transmission Planner	$0.03
Total NEM fees	$0.50

Source: ACIL Allen analysis of AEMO

4.4.2 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 2015-16, the cost of ancillary services is estimated to be $0.36/MWh.

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

4.4.3 Prudential costs

Prudential costs have been calculated for the Energex NSLP. These costs are then used as a proxy for prudential costs for all tariffs.

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 = OSL + PML

> Where for the Summer (December to March), Winter (May to August) and Shoulder (other months):
>
> OSL = (Average daily load x Average future expected spot price x Participant Risk Adjustment Factor * OS Volatility factor x Loss factor x (GST + 1) x 7 days
>
> PML = (Average daily load x Average future expected spot price x Participant Risk Adjustment Factor * PM Volatility factor x Loss factor x (GST + 1) x 35 days

Taking a 1 MWh average daily load and assuming the following inputs for each season for Energex NSLP:

Table 9 **AEMO prudential costs**

Factor	Summer	Winter	Shoulder
Load Weighted Expected Price	$70.75	$57.63	$57.01
Participant Risk Adjustment Factor	1.2094	1.1912	1.1668
OS Volatility factor	1.75	1.18	1.29
PM Volatility factor	3	1.42	1.43
Loss Factor	1.069	1.069	1.069
OSL	$7,453	$3,971	$4,121
PML	$1,491	$794	$824
MCL	$8,944	$4,766	$4,945
Average MCL		**$6,218**	

Source: ACIL Allen analysis

However as this applies for a rolling 42 days it actually covers 42 MWh of retailer purchases. Hence the portion of the MCL applicable to each MWh is $6,218/42 = $148/MWh.

The cost of funding a bank guarantee for the MCL associated with the single MWh is assumed to be a 2.5% annual charge[15] for 42 days or 2.5%*(42/366) = 0.287%. Applying this funding cost to the single MWh charge of $178 gives $0.425/MWh.

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

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

costs. The current money market rate is around 2.5%. 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 6.0% on average for a base contract
- the intra commodity spread charge currently set at $4,300 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 $46.40[16] and applying the above factors gives an average initial margin for each quarter of around $10,800 for a 1 MW quarterly contract. In order to allow for some ongoing future uncertainty we have rounded this to $11,000 per 1 MW quarterly contract. Dividing this by the average hours in a quarter then gives an initial margin of $5.02 per MWh. Assuming a funding cost of 9.72% (the approved WACC for Energex) but adjusted for an assumed 2.5% return on cash lodged with the clearing house gives a net funding cost of 7.22%. Applying 7.22% to the initial margin per MWh gives a prudential cost for hedging of $0.364/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.

4.4.4 Total prudential costs

Adding the AEMO and hedge prudential costs gives a total prudential requirement as set out in Table 10:

Table 10 **Total prudential costs ($/MWh) - 2014-15**

Cost category	Cost
AEMO pool	$0.43
Hedge	$0.36
Total	$0.79

4.4.5 Summary of estimated total other costs

Adding these component costs gives a total other cost requirement as set out in Table 11.

Table 11 **Total other costs ($/MWh) – 2015-16**

Cost category	Cost ($/MWh)
NEM management fees	$0.50
Ancillary services	$0.36
Hedge and pool prudential costs	$0.79
Total	$1.65

Source: ACIL Allen analysis

[16] Average annual price for base futures costs used in estimating WEC.

4.5 Estimation of energy losses

The methodology up to this point produces price estimates at the Queensland regional reference node (RRN). Prices at the Queensland RRN 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 reference 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 MLFs for the Energex and Ergon Energy east zone TNIs. This analysis resulted in a transmission loss factor of 1.007 for Energex and 1.043 for the Ergon Energy east zone. These estimates are based on AEMO's final 2014-15 MLFs weighted by the 2013-14 TNI energy.

The distribution loss factor by settlement class for the Energex area and the Ergon energy east zone are taken from AEMO's final DLFs for 2014-15 as the data for 2015-16 will not be available until 1 April 2015.

The estimated transmission and distribution loss factors for the settlement classes used in the Draft Determination shown in Table 12. The DLFs are the same as used in the Final Determination for 2014-15 as there has been no update in the loss factors by AEMO. However, the weighted MLFs have changed due to the changed TNI energy weightings and some MLF revisions in AEMO's final MLF document for 2014-15. For the Final Determination we expect to use the 2015-16 loss factors.

Table 12 **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	1.062	1.007	1.069
Energex - Control tariff 9000	1.062	1.007	1.069
Energex - Control tariff 9100	1.062	1.007	1.069
Ergon Energy - NSLP - SAC HV, CAC and ICC	1.034	1.043	1.078
Ergon Energy - NSLP - SAC demand and street lighting	1.094	1.043	1.141

Data source: ACIL Allen analysis based on Queensland TNIs energy for 2013-14, Queensland MLFs and Energex and Ergon Energy east zone DLFs for 2014/15 from AEMO.

For the Draft Determination ACIL Allen has applied the same methodology as used in the Final Determination for 2014-15 so that it aligns with the application of the transmission MLFs and DLF used by AEMO.

As described by AEMO[17], 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:

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

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

4.6 Summary of estimated energy costs

Drawing together the analyses from the previous sections of this report, ACIL Allen's estimates of the 2015-16 total energy costs (TEC) for the Draft Determination for each of the settlement classes are presented in Table 13.

Table 13 **Estimated TEC for 2015-16 Draft Determination**

Settlement class	WEC at Qld reference node ($/MWh)	Renewable energy costs at Qld reference node ($/MWh)	Market fees at the Qld reference node ($/MWh)	Total transmission and distribution loss factor (MLF x DLF)	Network losses ($/MWh)	TEC at the customer terminal ($/MWh)	Change from 2014-15 Final Determination ($/MWh)
Energex - NSLP - residential and small business	$63.42	$8.26	$1.65	1.069	$5.06	$78.39	1.6%
Energex - Control tariff 9000 (31)	$38.56	$8.26	$1.65	1.069	$3.34	$51.81	4.3%
Energex - Control tariff 9100 (33)	$49.72	$8.26	$1.65	1.069	$4.11	$63.74	-1.6%
Energex - NSLP - unmetered supply	$63.42	$8.26	$1.65	1.069	$5.06	$78.39	1.6%
Ergon Energy - NSLP - SAC HV, CAC and ICC	$55.60	$8.26	$1.65	1.078	$5.11	$70.62	-1.1%
Ergon Energy - NSLP - SAC demand and street lighting	$55.60	$8.26	$1.65	1.141	$9.24	$74.75	-1.0%

Source: ACIL Allen analysis