ACIL ALLEN CONSULTING

REPORT TO
QUEENSLAND COMPETITION AUTHORITY

17 MAY 2016

ESTIMATED ENERGY COSTS

2016-17 RETAIL TARIFFS

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

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ESTIMATED ENERGY COSTS FOR 2016-17 RETAIL TARIFFS: FINAL DETERMINATION, ACIL ALLEN, MAY 2016

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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 2016-17.

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 (non-market customers) for 2016-17. Although the QCA's determination is to apply only to the Ergon Energy distribution area, the TOR specifically requests that ACIL Allen's analysis cover the same tariff classes as covered in the analyses for the 2013-14, 2014-15 and 2015-16 determinations, and therefore includes residential and small business customers in south east Queensland.

This report provides estimates of the energy costs for use by the QCA in its Final Determination. These estimates have been revised slightly since the Draft Determination by taking into account feedback from the Draft Determination and updated market data.

This report also provides responses to submissions made by various parties following the release of the QCA's paper, *Draft determination: Regulated retail electricity prices for 2016–17* (March 2016), where those submissions refer to the cost of energy in regulated retail electricity prices.

ACIL Allen has separately been engaged to estimate the efficient retail operating cost (ROC) and retail margin (ROM) for a representative electricity retailer serving residential and business customers in Queensland as part of the 2016-17 review of regulated electricity tariffs. The analysis of the ROC and ROM are not the subject of this report, and are reported separately. Therefore, this report does not respond to submissions relating to ROC and ROM.

[1] http://www.qca.org.au/getattachment/881d7638-2be5-4bdc-8823-3b2dfe1e511f/2016-17-regulated-electricity-price-delegation.aspx
[2] http://www.qca.org.au/getattachment/a8b70fbb-d246-4b34-87be-4608dfcf507e/ACIL-Allen-terms-of-reference-energy-purchase-co.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 2016 to 30 June 2017.

In undertaking the task, ACIL Allen has not been asked to provide 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 (WEC) 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 follows the methodology used to provide advice to the QCA for the 2013-14, 2014-15, and 2015-16 Determinations, as well as the 2016-17 Draft Determination (please refer to ACIL Allen's report for the 2014-15 Draft Determination[3] and the 2014-15 Final Determination[4] for more details of the methodology).

The ACIL Allen methodology estimates costs from a retailing perspective. This includes wholesale energy market simulations to estimate expected pool costs and volatility and the hedging of the pool

[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

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.

2.3.1 Wholesale energy costs

As with the 2013-14, 2014-15 and 2015-16 reviews, ACIL Allen continues to use the market hedging approach for estimating the WEC for 2016-17.

We have utilised our:

- stochastic demand model to develop 45 weather influenced simulations of hourly demand traces for each of the tariff profiles – using temperature data from 1970-71 to 2014-15 and demand data for 2011-12 to 2014-15
- stochastic outage model to develop 11 hourly power station availability simulations
- energy market models to run 495 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, and OTC data from TFS Australia 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. It is our assessment that the AEMO medium series demand projection for 2016-17 provided in AEMO's 2015 National Electricity Forecasting Report (NEFR) plus the update provided by AEMO in December 2015 is the most reasonable demand forecast for the purposes of this analysis.

ACIL Allen has not made any revisions to the energy market modelling assumptions and methodology since the Draft Determination.

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 2016 and 2017 calendar years, with the costs averaged to estimate the 2016-17 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 targets (in GWh) for 2016 and 2017
- the Renewable Power Percentage (RPP) for 2016[5] as published by CER
- estimates of the RPP for 2017
- the binding Small-scale Technology Percentage (STP) for 2016[6] under the SRES as published by CER

[5] The CER is obligated to publish the official RPP for the 2016 compliance year by 31 March 2016 in accordance with Section 39 of the Renewable Energy (Electricity) Act 2000

[6] The CER is obligated to publish the official STP for the 2016 compliance year by 31 March 2016 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.

- estimates for the STP for 2017 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 representing capital used to meet prudential requirements to support hedging 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 month spread charge
  - the spot isolation rate.

As mentioned in the introduction, ACIL Allen is undertaking a separate analysis of the ROC and ROM for the QCA, and that separate analysis takes as an input the estimated prudential costs from this report (so as to avoid any double counting). ACIL Allen is of the opinion that prudential costs are associated with purchasing and hedging electricity and would apply to any NEM customer. Therefore they should be treated as a component of the energy cost rather than a cost associated with retailing.

2.3.4 Energy losses

The estimated wholesale energy costs resulting from the analysis is referenced to the Queensland Regional Reference Node (RRN). These estimates need to be adjusted for 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 wholesale energy cost estimates to incorporate losses.

Since the Draft determination, the MLFs and DLFs used in the calculations have been updated based on the final 2016-17 MLFs and DLFs published by AEMO on 1 April 2016 and 31 March respectively.

2.3.5 Extension of the data collection completion date

As with previous years, ACIL Allen has extended the data collection closure date for the Final Determination beyond the collection closure date of the Draft Determination. The closure date was set to 22 April 2016 for electricity and LGC contract data for the 2016-17 Final Determination, compared with a closure date of 12 January 2016 for the Draft Determination.

3 RESPONSES TO SUBMISSIONS TO THE DRAFT DETERMINATION

3.1 Introduction

The QCA forwarded to ACIL Allen a total of 70 submissions in response to its Draft Determination. ACIL Allen reviewed the submissions to identify issues that required our consideration. Of the 70 submissions, 10 raised issues that relate to the methodology for estimating energy costs[7]. **Table 3.1** summarises the submissions which have raised issues considered by ACIL Allen. The following sections in this chapter address each of the relevant issues raised in the submissions.

TABLE 3.1 INDICATION OF ISSUES RAISED IN SUBMISSIONS IN RESPONSE TO DRAFT DECISION

Id	Stakeholder	Wholesale energy costs	Contract prices / hedge model	Renewable energy policy costs	NEM fees	Prudential costs	Energy losses
1	Queensland Cane Growers Organisation Ltd (CANEGROWERS)	Yes	No	Yes	No	No	No
2	Cotton Australia	Yes	No	No	No	No	No
3	Ergon Energy Queensland Pty Ltd (EEQ) - Retail	Yes	No	Yes	No	No	No
4	Far North Queensland Electricity Users Network	Yes	No	No	No	No	No
5	Origin	Yes	No	No	No	No	No
6	Queensland Council of Social Service (QCOSS)	Yes	No	No	No	No	No
7	COTA Queensland	Yes	No	No	No	No	No
8	Ergon Energy Queensland Pty Ltd (EEQ) - Retail	Yes	No	Yes	No	No	No
9	Far North Queensland Electricity Users Network	Yes	No	No	No	No	No
10	Origin	Yes	No	No	No	No	No

Note: Yes = an issue was raised that required ACIL Allen's consideration

SOURCE: ACIL ALLEN ANALYSIS OF QCA SUPPLIED DOCUMENTS

[7] However, there were a large number of submissions which raised issues about the affordability of, and magnitude of the rise in, electricity prices and the impact of government policy on electricity prices over the medium to long term - issues which are outside ACIL Allen's terms of reference.

3.2 Wholesale energy costs

3.2.1 Overall approach

A number of the submissions supported the continuation of ACIL Allen's approach. QCOSS also noted the importance of the consistency in ACIL Allen's approach for estimating the energy costs for customers on notified retail prices for Queensland, and for estimating the energy costs in other regions of the NEM as part of ACIL Allen's methodology for estimating retail costs.

Some submissions commented on the level of wholesale electricity prices estimated by ACIL Allen and others focussed on the reasons for the increase in price and the impact of recent rule changes for re-bidding.

3.2.2 Wholesale energy cost levels

COTA notes on pages 2 and 3 of its submission:

It is alarming to note that the QCA is forecasting an increase in wholesale energy costs of around 15% over the next 12 months, and that a major driver of this cost increase is an increase in electricity demand from Queensland-based liquefied natural gas (LNG) projects. We note in ACIL Allen's report that AEMO has forecast energy consumption in Queensland to increase by over 6.7% between 2015-16 and 2016-17. We also note however, that Queensland's surplus generation capacity in 2016-17 is forecast to be around 2,000 megawatts. It is not apparent why energy prices should rise to such an extent when significant surplus generation capacity is available. COTA Queensland does not have the expertise to examine ACIL Allen's analysis or conclusions in detail, however we request that the QCA provides a more comprehensive explanation of this apparent contradiction in its Final Determination.

Cotton Australia notes on pages 4 and 5 of its submission that:

Cotton Australia is also dismayed by the assertion that some of the higher energy costs are associated with increasing demand as the Curtis Island CSG Trains come on stream. While these units no doubt have increased demand, it is not as if their commissioning is a surprise, and there had been plenty of time for generators to match supply with demand and therefore offer stable prices.

It is important that any energy cost estimate incorporate any industry structure effects. ACIL Allen's simulation model of the NEM, PowerMark, is specifically designed to take account of market concentration, demand-supply balance, market rules, and the subsequent expected commercial behaviour of generators when offering (bidding) their generation into the NEM. This includes scarcity pricing in expected times of extreme peak demand. Although there may be surplus generation capacity in the market, the cost of generation and market concentration are important contributors to price outcomes.

Demand from in-field compression associated with gas supply into the Liquefied Natural Gas (LNG) plants is projected to continue to increase electricity demand in Queensland, as well as increase fuel costs for gas-fired electricity generation. In 2015-16, Queensland gas-fired generators, owned by LNG proponents, transitioned from operating in baseload mode due to ramp gas, to opportunistic operations in response to the increased opportunity cost of gas. ACIL Allen's estimate for the price of gas delivered into gas-fired power stations in Queensland under contract in 2016-17 is about $9/GJ – compared with $3.50-$4/GJ in the period prior to the ramp-up of LNG production. This equates to a change in the cost of gas, in $/MWh terms, for a typical gas-fired combined cycle gas turbine (CCGT) from about $28/MWh prior to LNG to about $64/MWh in 2016-17, or an increase of $36/MWh.

The pending, and continued, commissioning of the LNG export facilities was contemplated by generators in advance, along with an increase in wholesale electricity prices. However, it is important to note that although wholesale electricity prices are rising they are yet to reach levels sufficient to incentivise the investment in new generation capacity – due to the increase in power station input costs (i.e. fuel and capital costs).

3.2.3 Behaviour of Queensland Government owned generators

Queensland Cane Growers Organisation (CANEGROWERS) state on pages 2 and 3 of their submission that:

QCA should review the effect of recent changes to the rules around generator rebidding recently finalised by the AEMC. These changes are in response to clear evidence that Queensland generators in particular took advantage of the previous rules around rebidding in order to exercise market power and increase wholesale energy prices, including a prudent allowance for energy trading risk. While the Queensland sector will remain concentrated, the AEMC adopted the rule change for rebidding on the basis that, overall, the additional costs from adopting the new rules would be exceeded by the benefits, in the form of lower wholesale prices than otherwise. Against this background, QCA needs to reconsider its implicit finding that the AEMC conclusions on this point are incorrect.

Similarly, COTA note on pages 2 and 3 of their submission:

COTA Queensland suggests that the intent of the AEMC's rule change is to change generator bidding behaviour, not simply to make it more transparent. In assessing any changes to forecast wholesale energy costs for the Final Report, we request that the QCA and ACIL Allen reconsider whether an adjustment should be made to the ACIL Allen model to reflect some element of the expected changes in generator bidding behaviour.

ACIL Allen agrees with CANEGROWERS and COTA that the December 2015 change to the National Electricity Rules, made by the Australian Energy Market Commission (AEMC) in regard to generator bidding behaviour, is intended to lead to more efficient wholesale price outcomes in the short term. However, it is difficult to assess the impact of the rule change, and predict whether generators will modify their behaviour in response to the rule change, such as by changes to bidding, contracting or mothballing of plant. Certainly the contract market would be reflecting any expected change in wholesale electricity prices as a result of the rule change. However, it is very difficult to disentangle the impact of the rule change from other factors which influence the levels of the contract prices. ACIL Allen notes that for 2017, ASX Energy contract prices for annual base contracts have increased by about $5/MWh since the release of the AEMC's final determination (noting the rule change comes into effect from 1 July 2016).

ACIL Allen remains of the view that, since the rule change does not result in any change to the underlying degree of wholesale market concentration, or underlying costs of generation, in the Queensland region of the NEM, and that there is no evidence to date in the contract market suggesting a notable decline in market prices as a result of the rule change, it is appropriate to continue to model the NEM using its usual approach.

3.2.4 Contract prices and the hedge model

Origin Energy states on page two of their submission to the Draft Determination that:

As stated in previous submissions, it is Origin's view that the QCA's hedging based method does not appropriately reflect the dynamic of the wholesale market with respect to the relationship between contract and pool prices. Under the QCA's approach, the portfolio cost is at its lowest under a scenario when pool prices are at their highest and the supply demand balance is at its tightest; conversely, portfolio costs are at their highest under a situation when pool prices and demand are at their lowest. This approach has been taken by the QCA over the previous three years.

Our experience is that when the supply demand balance is tight, generators have more ability to price contracts at higher values to reflect the value of scarce capacity. Furthermore, we consider that historic practise demonstrates that when pool prices are high so too are contact prices.

As a result, we maintain our view that it is unrealistic to assume retailers will consistently be able to profit from buying an insurance product and that the higher the pool price scenario, the lower the wholesale energy cost. This would be the third consecutive year that the QCA's approach has assumed a positive payoff from 'insurance' products to the retailer.

ACIL Allen notes that Origin Energy has made similar comments in submissions in previous years.

ACIL Allen addressed this matter in detail in its report for the 2014-15 Final Determination (page 24), and provides a summary excerpt of the explanation below.

Although we agree that for a given quarter, futures contract prices will converge to the spot price at the completion of that quarter, this does not mean that all trades in futures contracts are priced at the final spot price for the quarter. Trades completed prior to the completion, or indeed the commencement, of the quarter will have occurred at the prevailing futures price at the time of the trade which reflects the relative future expectations for that quarter at the time of each trade for both buyers and sellers.

The hedging approach adopted in this review, and in previous reviews, makes the assumption that for a given quarter, retailers complete the hedging of their retail load prior to the commencement of the quarter. Moreover the standard hedging approach is risk averse – resulting in an over hedging of the portfolio position for the majority of half hours in the year. This means that the contract prices used dominate the simulated pool prices in estimating the energy cost. As these contract prices are derived from observable futures market transactions, they encapsulate the market's current view of the relative tightness (or looseness) of the supply-demand balance.

The outcomes of the standard risk averse hedging strategy is that in general, the hedged cost tends to be lower should the spot prices be higher than the expected spot price (especially during peak periods, since the retailer would receive a greater value in difference payments from the contract counterparty than what it is making in spot payments to AEMO). The ACIL Allen 495 pool simulations reflect different pool scenarios based on prevailing market conditions with the variability driven by short term weather and outage effects. The higher and lower prices derived from the 495 simulations do not reflect different views of the supply-demand balance, but rather the current view for the likely range of weather and outage effects.

Therefore, where a buyer purchases a contract based on a future expected price (reflected in the contract price) but actual weather and outages result in much higher prices than expected, then the payout on the contract would be much more than expected by the buyer, at the time of purchase. That this is reflected in the estimated energy costs being lower for a portfolio that is assumed to be biased to over hedging is expected and is consistent with both our and Origin Energy's understanding of how the NEM and electricity price hedging operates.

3.3 Renewable energy policy costs

Ergon Energy Queensland (EEQ) note and suggest on pages 2 and 3 of their submission:

EEQ reiterates its position from its submission to the QCA's Interim Consultation Paper that the regulatory uncertainty associated with the Federal Government's RET review significantly affected the efficient operation of the market, increasing the risk of forward purchases to cover future liabilities. This risk materialised in an observed suppression in market activity as participants avoided building long Large-scale generation certificate (LGC) positions pending the outcome of the review. This behaviour ultimately flowed through to an artificial suppression in the LGC price over the period.

Due to this, ACIL's approach of examining market prices over a two year period does not reflect the behaviour of an efficient retailer (as demonstrated by market behaviour) in the face of the significant regulatory intervention.

Although the price has increased since the 2015/16 determination, EEQ's position is that the costs determined in 2015/16 did not reflect the hedging costs an efficient retailer would reasonably face and this issue remains in the 2016/17 draft determination.

EEQ recommends that the QCA consider the impact of such policy interventions on the efficient operation of the market when determining a method for estimating LGC prices.

Conversely, CANEGROWERS state on page 3 of their submission that:

QCA should reduce the allowance for LRET to reflect efficient costs of producing large scale renewable energy. The Draft Determination adopts a market based approach to estimate LRET costs. Due to the current "hiatus" in renewable energy project construction, recent LRET market prices do not reflect the actual cost of producing renewable energy. Instead, they reflect the post-tax effect of the penalty applicable to liable entities that fail to meet their renewable energy obligations. If retailers are allowed to pass through almost in full the costs of failing to meet their LRET obligations, this further weakens incentives for retailers to procure sufficient LRET certificates or physical output and hence undermines *the integrity of LRET. The Draft Determination undermines the integrity of the LRET and this is inconsistent with the relevant statutory criteria.*

The uncertainty around the RET review conducted in 2014 resulted in LGC futures prices declining in 2014. The lower priced periods linked to the period of the RET Review effectively included the likelihood of the Review recommending a lower target or the abolition of the RET, and the likelihood of the Government legislating such recommendations. In ACIL Allen's view, a prudent retailer operating a portfolio based approach to risk management, as assumed in the methodology, would have acquired some LGCs during the period of the RET review.

ACIL Allen notes that Governments historically have not usually made major policy changes without a period of transition to the new policy. In our view, a prudent retailer could also have put some weight on such precedence had the RET been abolished.

Conversely, over the past 12 months LGC prices have increased as the level of banked LGCs diminishes and liable parties attempt to secure supply to meet future obligations. ACIL Allen agrees that the hiatus in large-scale renewable developments, has contributed to the tightening of the LGC market and, may be partly attributed to the 2014 RET Review.

ACIL Allen does not agree with CANEGROWERS' assertion that including in our analysis LGC prices approaching the penalty reduces the incentives for retailers to procure sufficient LGCs. The very reason LGC prices are approaching penalty levels is the impending shortfall and scarcity of LGCs and retailers attempting to satisfy their obligations. ACIL Allen is aware of increased activity in the market of several large-scale renewable energy developments, which if developed will contribute to the increased supply of LGCs and hence lower LGC prices faced by retailers in the future. Recent retailers' announcements, such as Ergon Energy Retail's shortlist of applicants to supply 150 MW of renewable energy, AGL's Powering Australian Renewables Fund's intention to secure about 1,000 MW of renewable capacity, and Origin's signing of a PPA with Clare Solar Farm, suggest a strengthening in activity by retailers to procure additional sources of renewable energy to satisfy their LRET obligations.

Therefore 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 faced by retailers in attempting to satisfy their obligations under the LRET.

4

ESTIMATION OF ENERGY COSTS

4.1 Introduction

In this section we apply the methodology described in chapter 2 and summarise the estimates of each component of the Total Energy Cost for each of the tariff classes for 2016-17.

4.2 Estimation of the Wholesale Energy Cost

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 22 April 2016.

Table 4.1 shows the estimated quarterly swap and cap contract prices for the Final Determination 2016-17 and compares them with the estimates under the Draft Determination 2016-17 and the Final Determination 2015-16.

TABLE 4.1 ESTIMATED CONTRACT PRICES ($/MWH)

	Q3	Q4	Q1	Q2
		Final Determination 2016-17		
Base	$44.77	$54.11	$71.19	$45.16
Peak	$54.14	$68.18	$111.06	$57.25
Cap	$4.81	$10.48	$21.00	$5.01
		Draft Determination 2016-17		
Base	$44.20	$53.46	$68.99	$44.18
Peak	$53.41	$66.78	$105.50	$59.00
Cap	$4.63	$10.60	$21.35	$5.01
		Final Determination 2015-16		
Base	$38.92	$45.72	$60.05	$41.15
Peak	$46.25	$62.75	$95.86	$48.49
Cap	$3.57	$7.89	$14.89	$3.95

SOURCE: ACIL ALLEN ANALYSIS USING ASX ENERGY DATA UP TO 22 APRIL 2016

Trade weighted contract prices for 2016-17 are higher than for 2015-16, due to anticipated strong demand growth in Queensland, gas-fired generators offering capacity into the market at higher prices, and an expected reduction in plant availability across the NEM. These three points are discussed in further detail in the dot points below.

— The latest AEMO NEFR Update published in December 2015 forecasted energy in Queensland to increase by over 6.7 per cent between 2015-16 and 2016-17, driven by gas compression loads associated with the LNG export projects coming online during this period.
— Gas prices continue to increase in the spot market, which improves confidence in the view that over the medium to long term contracted gas prices into power stations are on the rise.
— AEMO's MT PASA reports[8] for July, August and September 2015 forecasted very tight supply-demand conditions across the NEM during 2016-17, which was followed by an up-kick in futures prices. The tight supply-demand conditions include, but are not limited to, strong expected demand growth in Queensland and a significant decrease in plant availability in South Australia with the announced closure of Northern power station in 2016. South Australia is a net importer of energy and as such the closure of Northern is expected to result in increased flows from Victoria to South Australia, reduced flows from Victoria to New South Wales and increased flows from Queensland to New South Wales. This is expected to drive higher wholesale prices, not only in South Australia, but also across the NEM.

Trade weighted contract prices for the Final Determination 2016-17 are on average around 2 per cent higher than the Draft Determination 2016-17. There are some reasons that may explain this increase:

— Since the Draft Determination it is possible that uncertainty about the exact timing of commissioning of the LNG projects has diminished - noting that revisions have been made in the past by Powerlink and AEMO in terms of LNG related electricity demand forecasts over the past couple of years. Santos shipped their first LNG cargo in the December quarter of 2015, and APLNG shipped their first LNG cargo in mid-January 2016, which may well have improved market confidence on the impact of LNG on electricity demand over the coming year or two.
— The NEM has experienced five or so years of declining electricity demand, but as projected by AEMO last year, electricity demand is now demonstrating the early stages of a recovery, with peak demand either stabilising or increasing over the past 12 months, and confidence in this projected modest recovery may well have improved with the completion of the 2015-16 summer. It could be argued that the recent summer has been more drawn out than usual and that this could contribute to the modest recovery in demand but even in the summer months that were not particularly hot, peak demand has increased or stabilised in most regions compared with previous summers.
— Around 20 per cent of total trades in contracts since commencement of the 2016-17 quarterly contracts have occurred between January 2016 and April 2016 (or since the Draft Determination), which places emphasis on the higher prices during this period.

The following charts show daily settlement prices and trade volumes for ASX Energy quarterly base futures, peak futures and cap contracts up to 22 April 2016.

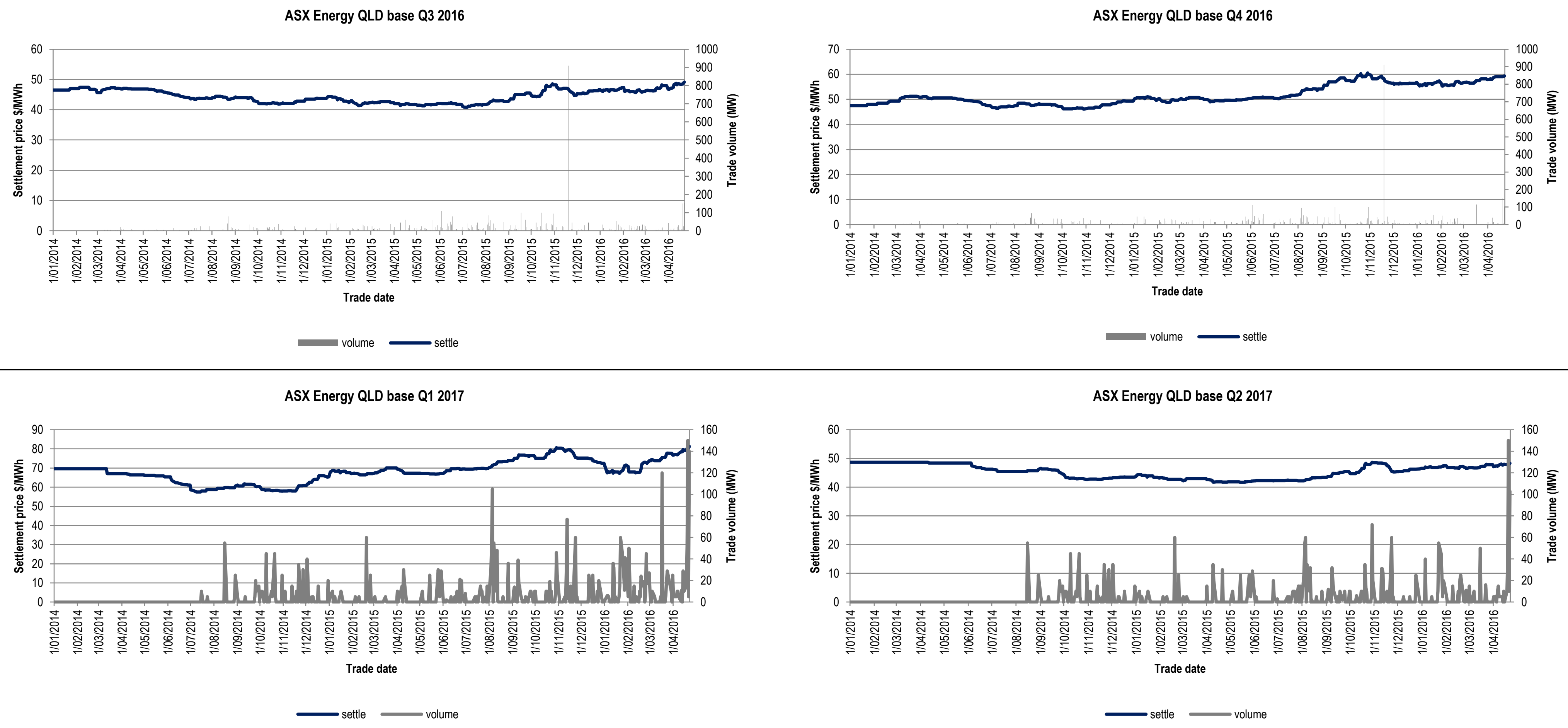
Base futures have traded strongly, with total volumes of 6,108 MW (Q3 2016), 5,824 MW (Q4 2016), 3,286 MW (Q1 2017), and 2,536 MW (Q2 2017).

Cap futures trade volumes also traded strongly with volumes of 1,166 MW (Q3 2016), 926 MW (Q4 2016), 1,053 MW (Q1 2017) and 320 MW (Q2 2017).

2016 peak futures traded strongly with 195 MW (Q3 2016) and 107 MW (Q4 2016), however, 2017 peak futures traded relatively weakly with 17 MW (Q1 2017) and 5 MW (Q2 2017). While 2017 peak futures are thinly traded, we are comfortable with using the ASX Energy prices because they are consistent with over-the-counter (OTC) peak contract prices.[9]

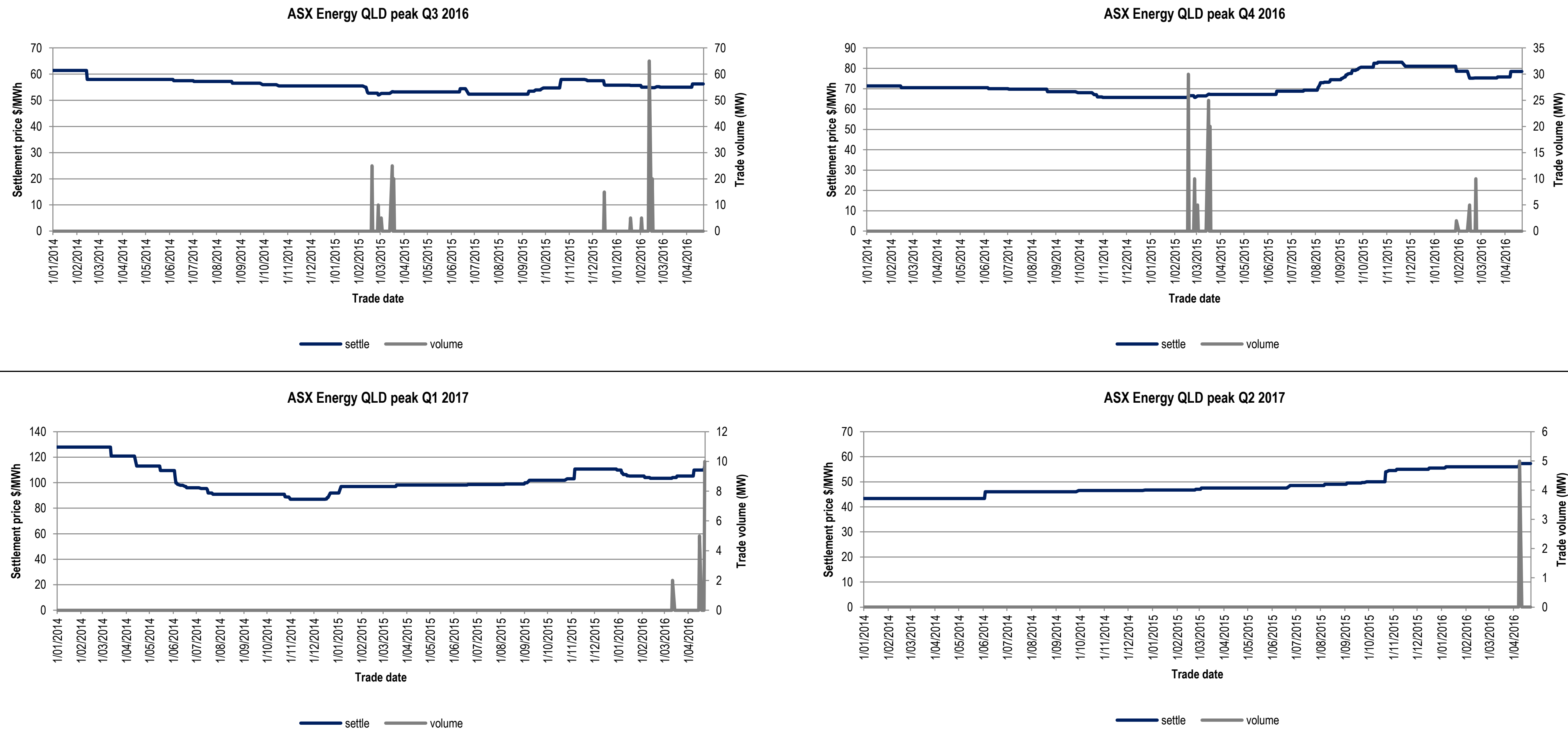
[8] AEMO's Medium term projected assessment of system adequacy (MT PASA) process is a forecast of power system security and supply reliability of electricity for a period of 2 years.
[9] OTC contract data from TFS brokers

FIGURE 4.1 TIME SERIES OF TRADE VOLUME AND PRICE – ASX ENERGY QUEENSLAND BASE FUTURES



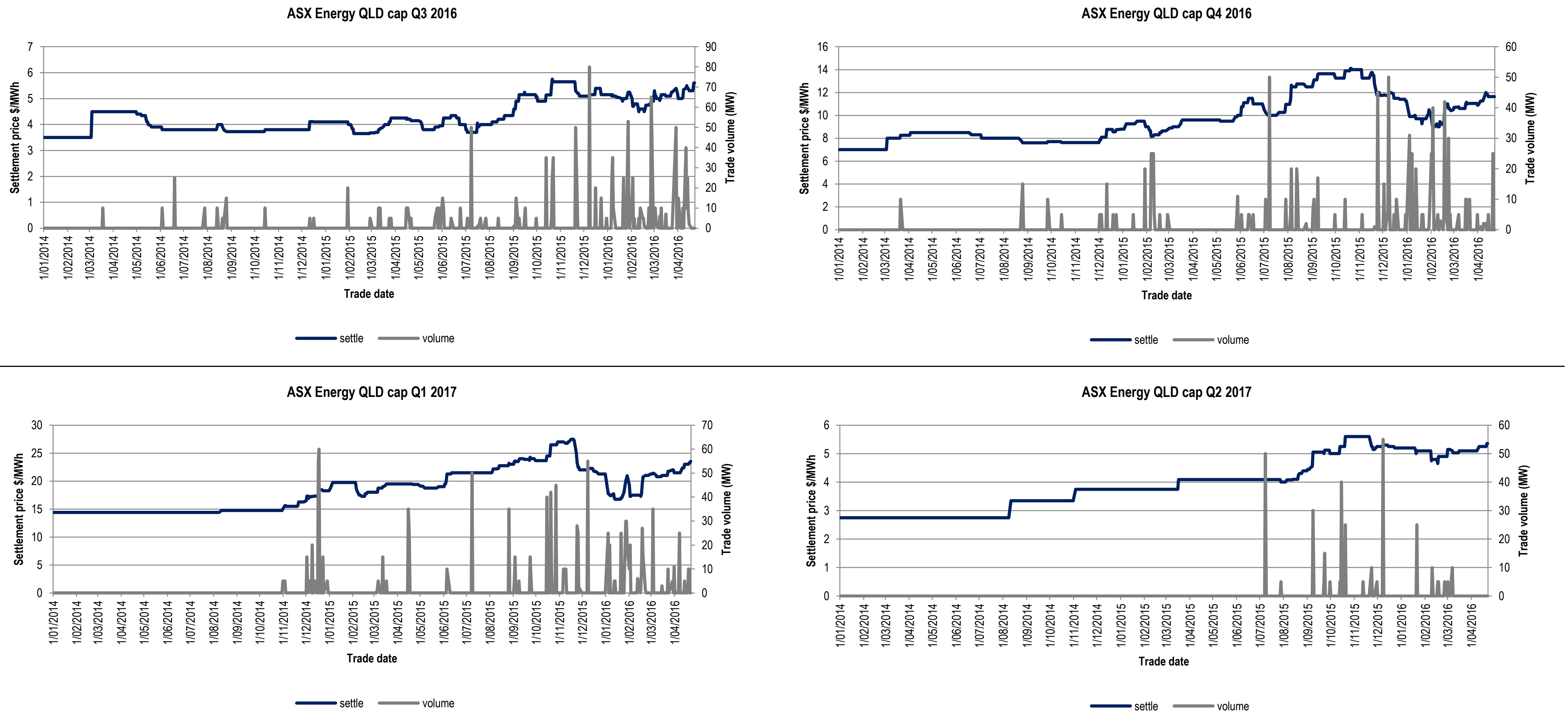
SOURCE: ASX ENERGY DATA UP TO 22 APRIL 2016

FIGURE 4.2 TIME SERIES OF TRADE VOLUME AND PRICE – ASX ENERGY QUEENSLAND PEAK FUTURES



SOURCE: ASX ENERGY DATA UP TO 22 APRIL 2016

FIGURE 4.3 TIME SERIES OF TRADE VOLUME AND PRICE – ASX ENERGY QUEENSLAND $300 CAP CONTRACTS



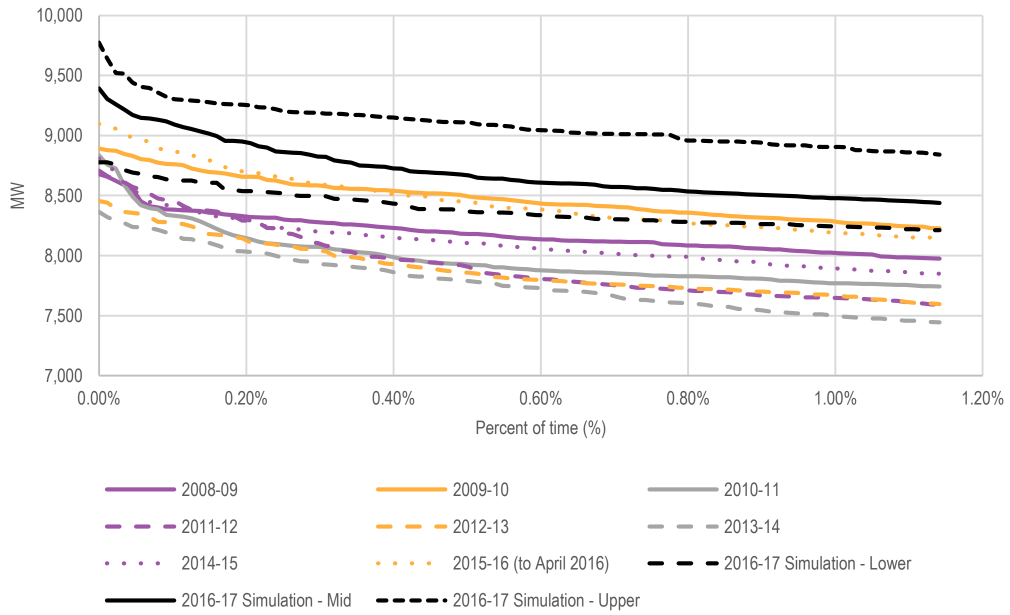
SOURCE: ASX ENERGY DATA UP TO 22 APRIL 2016

4.2.2 Estimating wholesale spot prices

ACIL Allen's proprietary electricity model, *PowerMark* was run to estimate the hourly pool prices for 2016-17 for the 495 simulations (45 demand and 11 outage sets). As mentioned earlier, ACIL Allen found no reason to update the hourly simulations of 2016-17 since the Draft Determination.

Figure 4.4 shows the range of the upper one percent segment of the demand duration curves for the 45 simulated Queensland demand sets resulting from the methodology, along with the historical demands since 2008-09. The simulated demand sets represent the upper, lower and middle of the range of demand duration curves across all 45 simulated sets. It can be seen that the demand duration curves of the simulated demand sets for 2016-17 have a variation similar to that observed over the past seven years - 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[10]. This variation in demand contributes to the variation in modelled pool price outcomes as discussed further in this section.

FIGURE 4.4 TOP ONE PERCENT HOURLY DEMANDS – QUEENSLAND



SOURCE: ACIL ALLEN ANALYSIS AND AEMO DATA

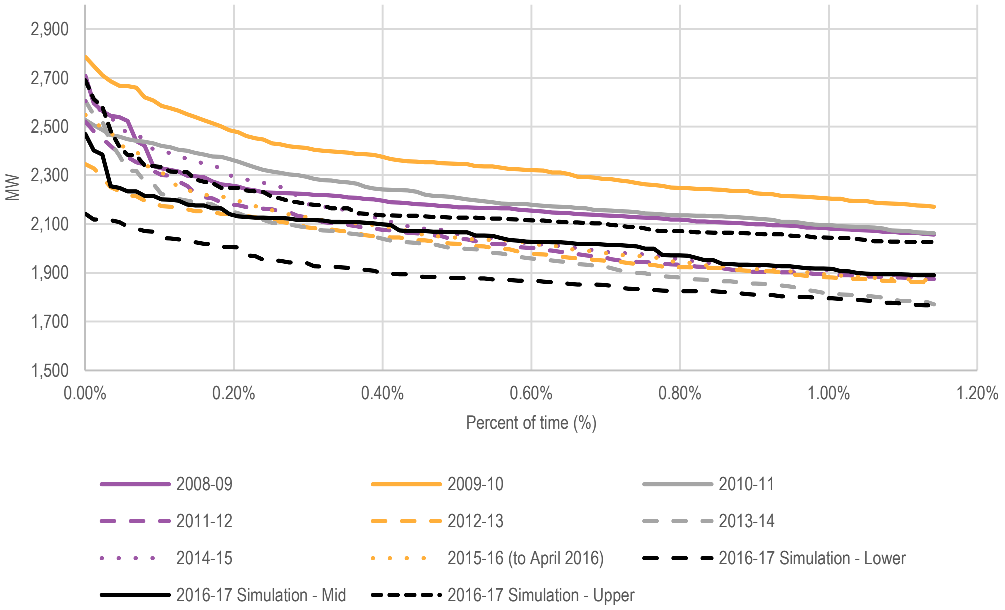
Figure 4.5 shows the range of the simulated Energex NSLP demand envelopes recent outcomes and covers an average range of about 500MW across the top one percent of hours. This variation results in the annual load factor[11] of the 2016-17 simulated demand sets ranging between 31 percent and 38 percent compared with a range of 40 percent to 33 percent for the actual NSLP between 2008-09 and 2015-16. There has been an observable fall in the load factor in the actual NSLP 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 now occurs between 6:30pm and 8:30pm) but continues to reduce the average metered demand throughout the middle of the day.

All other things being equal, the increased peakiness of the load, which is hedged under the methodology, is likely to result in a larger degree of over hedging across the general day-time peak periods, resulting in a larger degree of over hedging overall on an annual basis, which means estimated hedging costs will increase.

[10] The simulated demand sets for 2016-17 are generally higher than the recent observed demand outcomes due to the step increase in demand due to the in-field compression associated with the LNG export projects in Gladstone.

[11] 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 4.5 TOP ONE PERCENT HOURLY DEMANDS – ENERGEX NSLP

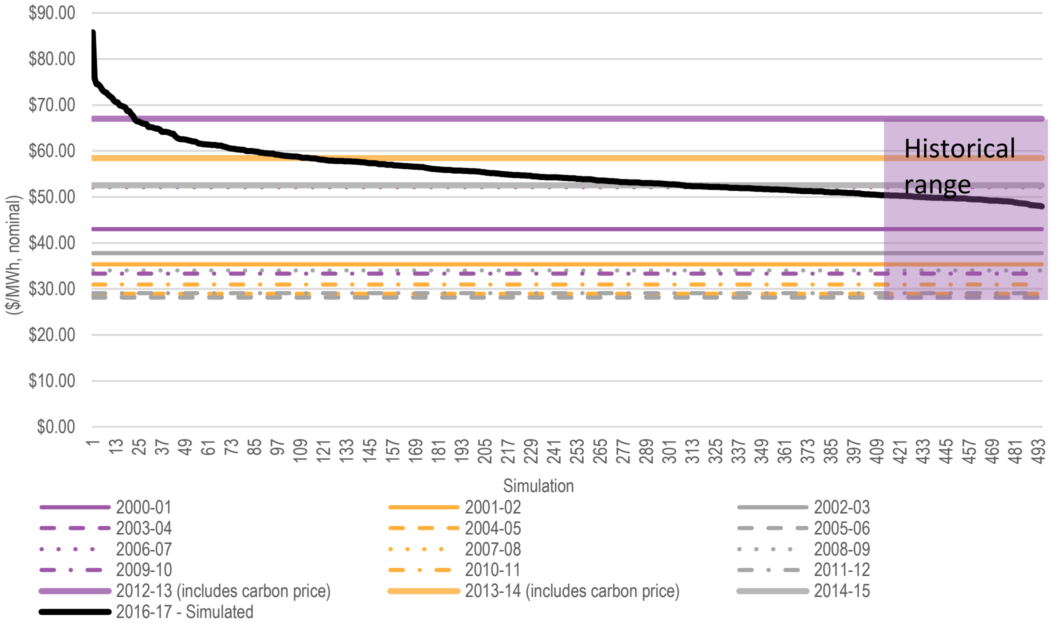


SOURCE: ACIL ALLEN ANALYSIS AND AEMO DATA

The modelled annual time weighted pool prices (TWP) for Queensland in 2016-17 from the 495 simulations range from a low of $47.95/MWh to a high of $85.80/MWh. This compares with the lowest recorded Queensland TWP in the last 15 years of $28.12/MWh in 2005-06 to the highest of $67.02/MWh in 2012-13.

Figure 6 compares the modelled Queensland TWP for the 495 simulations for 2016-17 with the Queensland TWPs from the past 15 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 2016-17 when compared with the past 15 years of history. The lower part of the distribution of simulated outcomes sits above a number of the actual outcomes (particularly for the earlier years of the market), but by 2016-17 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 the assumed substantial demand growth due to the LNG terminals, have the effect of influencing an increase in the lower bound of annual price outcomes. ACIL Allen is satisfied that in an aggregate sense the distribution of the 495 simulations for 2016-17 cover an adequately wide range of possible annual pool price outcomes.

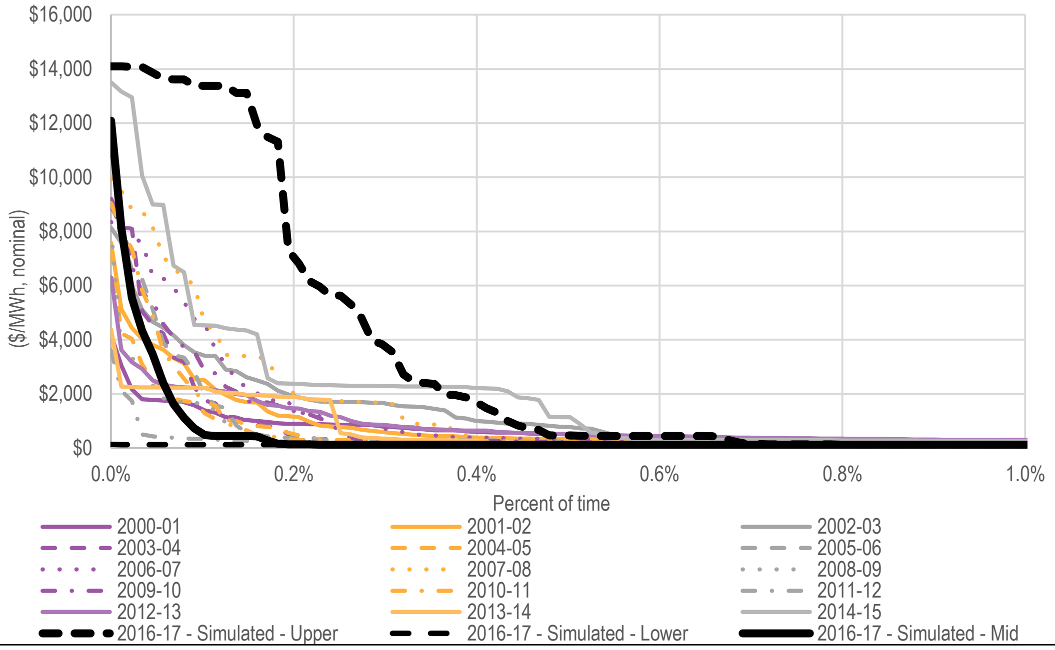
FIGURE 4.6 ANNUAL TWP FOR QUEENSLAND FOR 495 SIMULATIONS FOR 2016-17 COMPARED WITH ACTUAL ANNUAL OUTCOMES IN PAST YEARS



SOURCE: AEMO HISTORIC POOL PRICE DATA AND ACIL ALLEN RESULTS FROM POWERMARK MODELLING

Comparing the upper one percent 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, as shown in in **Figure 4.7**. It is also notable, that as would be expected, the distribution of simulated price outcomes demonstrates a strong positive skewness.

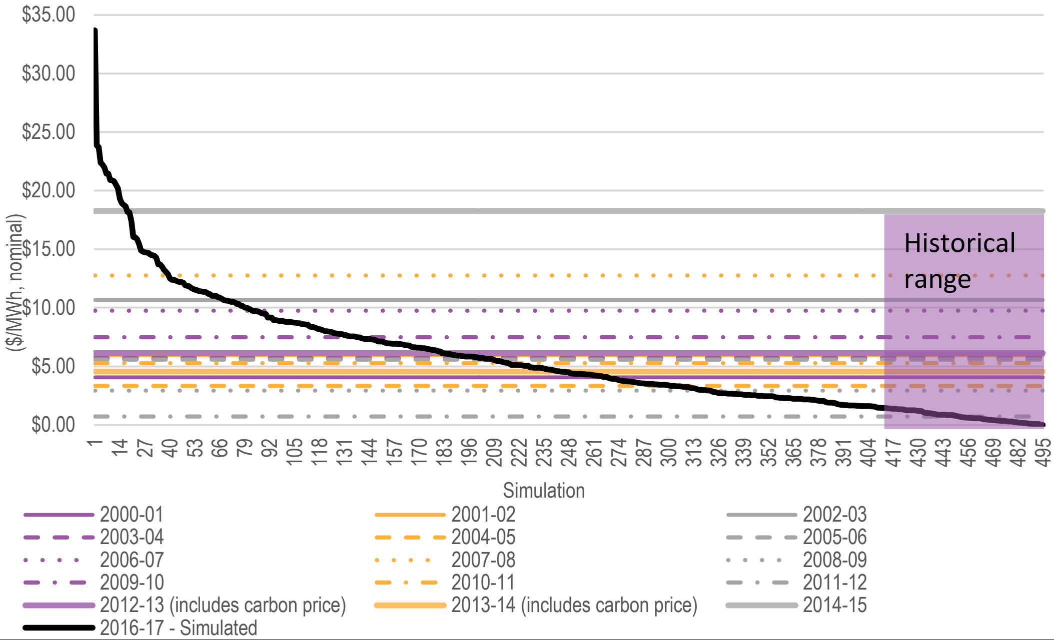
FIGURE 4.7 COMPARISON OF UPPER 1 PERCENT TAIL OF SIMULATED HOURLY PRICE DURATION CURVES FOR QUEENSLAND AND HISTORICAL OUTCOMES



SOURCE: AEMO HISTORIC POOL PRICE DATA AND ACIL ALLEN RESULTS FROM POWERMARK MODELLING

ACIL Allen is satisfied that *PowerMark* has performed adequately in capturing the extent and level of high price events based on the demand and outage inputs for the 495 simulations. The range in annual average contribution to the TWP, of hourly prices above $300/MWh, for the 495 simulations is consistent with those recorded in history as shown in **Figure 4.8**.

FIGURE 4.8 ANNUAL AVERAGE CONTRIBUTION TO THE QUEENSLAND TWP BY PRICES ABOVE $300/MWH FOR QUEENSLAND IN 2016-17 FOR 495 SIMULATIONS COMPARED WITH ACTUAL OUTCOMES IN PAST YEARS

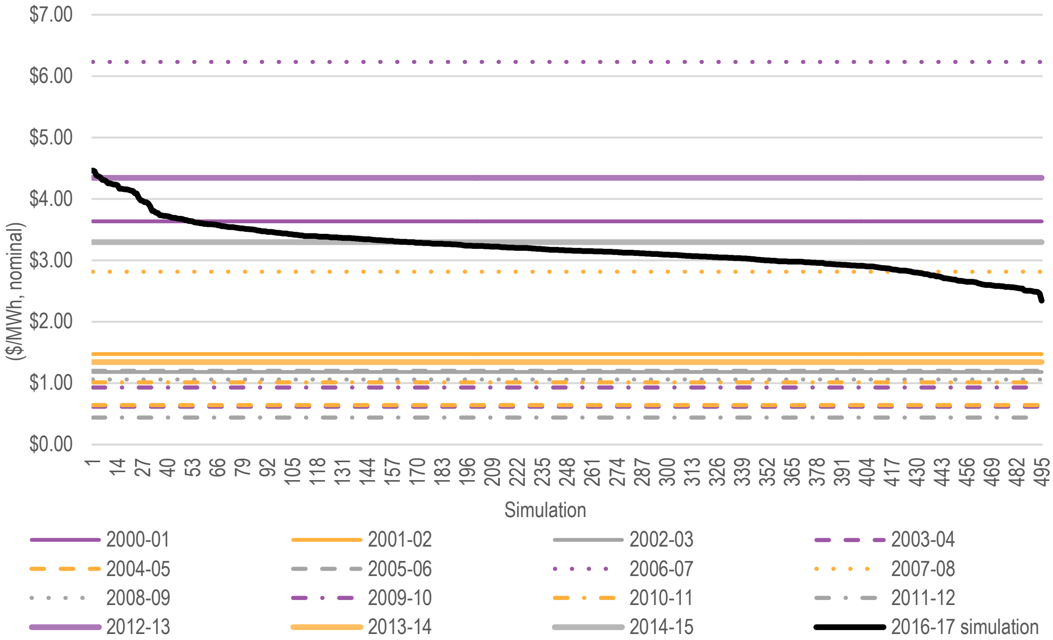


SOURCE: AEMO HISTORIC POOL PRICE DATA AND ACIL ALLEN RESULTS FROM POWERMARK MODELLING

Figure 4.9 shows the range in annual average contribution to the Queensland time weighted price (TWP), of hourly prices between $70/MWh and $300/MWh, for the 495 simulations is also consistent with those recorded in history.

At the peak of the drought in 2006-07 scarcity of water for some water cooled coal fired plant and for some hydro plant increased the opportunity cost for generation from these technologies and hence increased the number of price events in the $70 to $300 price range, thereby increasing the contribution of these prices to the annual price to about $6.20/MWh. The simulation of 2016-17 does not produce outcomes to the extent that were experienced during the drought – but we are assuming (in our view quite reasonably) that the drought conditions of 2006-07 are not repeated in 2016-17. The simulations indicate that the increased demand assumed in Queensland associated with the LNG export facilities in 2016-17 results in the hourly prices between $70/MWh and $300/MWh increasing the Queensland TWP on average by about $3/MWh.

FIGURE 4.9 ANNUAL AVERAGE CONTRIBUTION TO THE QUEENSLAND TWP BY PRICES BETWEEN $70/MWH AND $300/MWH IN 2016-17 FOR 495 SIMULATIONS COMPARED WITH ACTUAL OUTCOMES IN PAST YEARS



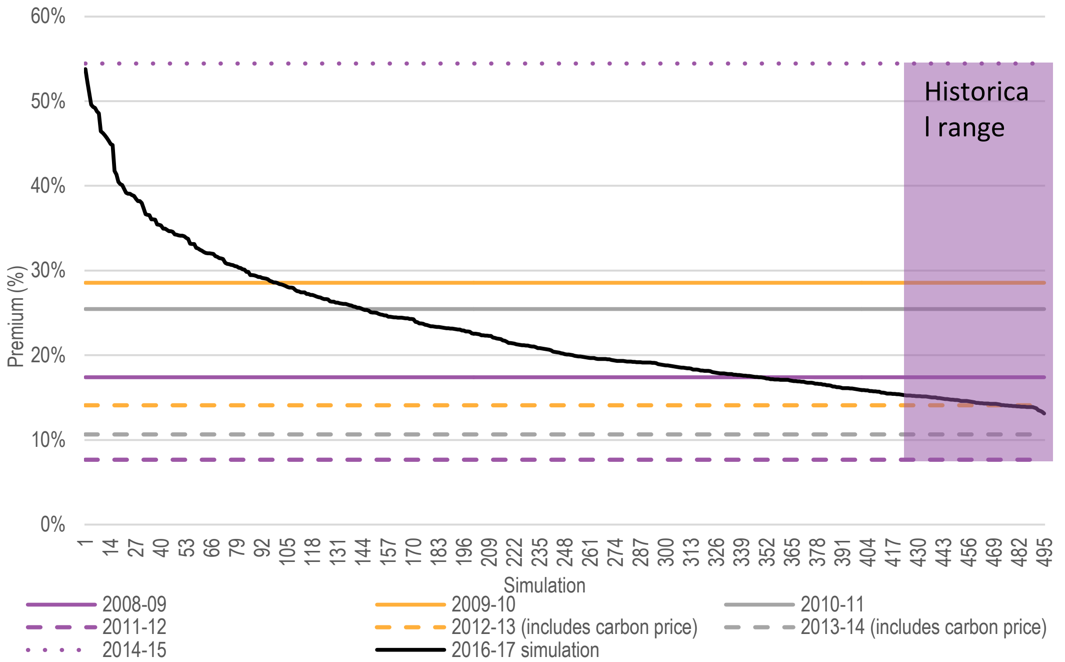
SOURCE: AEMO HISTORIC POOL PRICE DATA AND ACIL ALLEN RESULTS FROM POWERMARK MODELLING

Submissions to previous determinations suggested that the simulated NSLP peak demand was too low which in turn was 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.

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 4.10** shows that, for the past six financial years, the DWP for the Energex NSLP as a percentage premium over the Queensland TWP has varied from a low of 8 percent in 2011-12 to a high of 54 percent in 2014-15. In the 495 simulations for 2016-17, this percentage varies from 13 percent to 54 percent.

The comparison with actual outcomes over the past five years in **Figure 4.10** demonstrates that the relationship between the Energex NSLP demand and Queensland pool prices in the 495 simulations is sound. Further, the cost of supplying the Energex NSLP from the spot market in the simulations relates well to the Queensland pool price and covers an adequate range of possible outcomes for 2016-17. It also provides a sound cross check on the shape of the NSLP demand and its relationship with the Queensland demand.

FIGURE 4.10 ANNUAL DWP FOR ENERGEX NSLP AS PERCENTAGE PREMIUM OF ANNUAL TWP FOR QUEENSLAND FOR 484 SIMULATIONS FOR 2016-17 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 modelled Queensland pool prices from the 495 simulations cover the range of expected price outcomes for 2016-17 in terms of annual averages and distributions. These comparisons clearly show that the 45 simulated demand traces combined with the 11 plant outage scenarios provide a sound basis for modelling the expected future spot market outcomes for 2016-17.

4.2.3 Applying the hedge model

The hedging methodology uses a simple hedge book approach based on standard quarterly base and peak swaps, and caps contracts. The prices for these hedging instruments are taken from the updated estimates provided in Section 4.2.1.

Contract volumes continue 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 45 demand sets for the quarter.

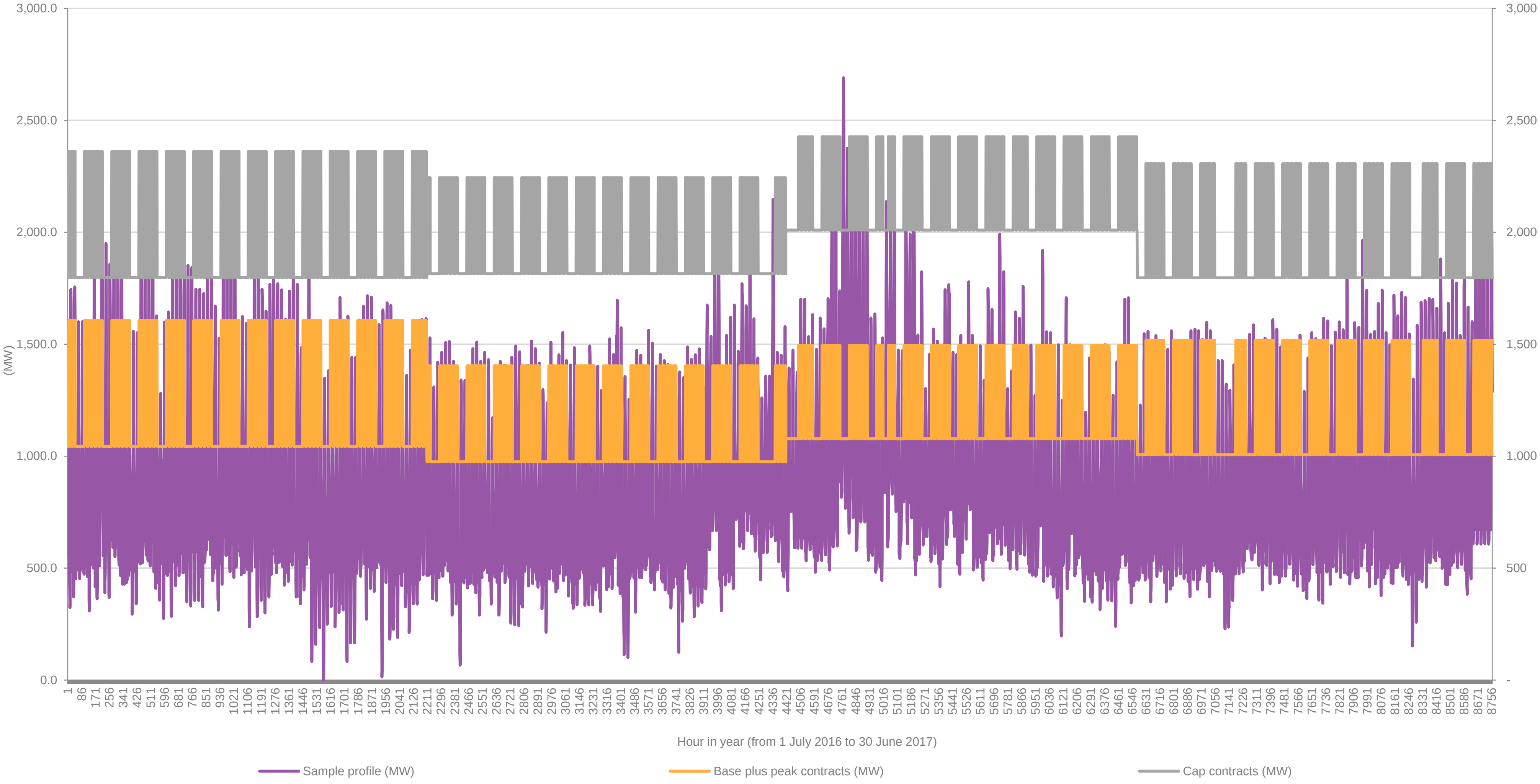
— The peak period contract volume is set to equal the 90th percentile of the peak period hourly demands across all 45 demand sets for the quarter.

— The cap contract volume is set at 105 per cent of the median of the annual peak demands across the 45 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 45 demand sets for a given settlement class, and hence to each of the 495 simulations. To be clear, we are not altering the hedge volume (in MW terms) on an ex-post basis for each of the 45 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 495 simulations when calculating the wholesale energy cost. The contract volumes used are shown in **Figure 4.11**.

FIGURE 4.11 CONTRACT VOLUMES USED IN HEDGE MODELLING OF 495 SIMULATIONS FOR 2016-17 FOR ENERGEX NSLP

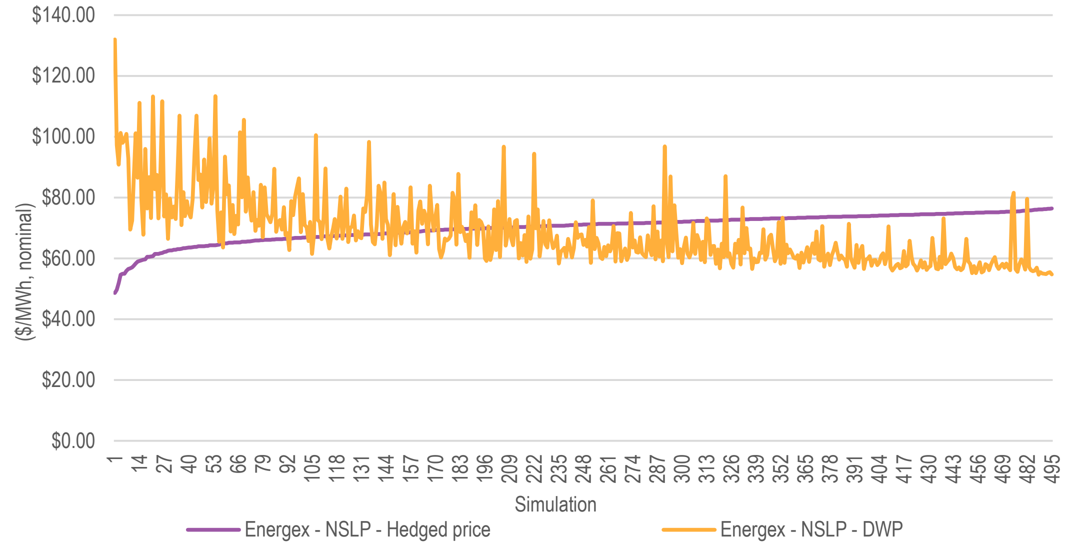


SOURCE: ACIL ALLEN

As hedge benefits are inversely related to pool prices, simulations with higher demand weighted pool prices usually produce lower hedged prices. **Figure 4.12** shows that, under the current methodology, the higher estimates of supply costs including hedge effects are not associated with high demand and high pool price years.

In other words the current risk averse hedging strategy adopted in methodology 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 4.12 ANNUAL HEDGED PRICE AND DWP ($/MWH, NOMINAL) FOR ENERGEX NSLP FOR THE 495 SIMULATIONS - 2016-17



SOURCE: ACIL ALLEN MODELLING

4.2.4 Summary of estimated Wholesale Energy Cost

After applying the hedge model, the WEC was taken as the 95th percentile of the distribution containing 495 annual hedged prices. ACIL Allen's estimate of the WEC for each tariff class for the 2016-17 Draft Determination are shown in **Table 4.2**.

TABLE 4.2 ESTIMATED WEC ($/MWH, NOMINAL) FOR 2016-17 AT THE QUEENSLAND REFERENCE NODE

Settlement class	2016-17 – Final Determination	2016-17 – Draft Determination	2015-16 – Final Determination	Change from 2015-16 to 2016-17 (%)
Energex - NSLP - residential and small business	$75.32	$73.67	$63.73	18.2%
Energex - Control tariff 9000 (31)	$42.31	$41.55	$36.10	17.2%
Energex - Control tariff 9100 (33)	$56.15	$55.04	$50.39	11.4%
Energex - NSLP - unmetered supply	$75.32	$73.67	$63.73	18.2%
Ergon Energy - NSLP - SAC HV, CAC and ICC	$65.69	$64.22	$55.70	17.9%
Ergon Energy - NSLP - SAC demand and street lighting	$65.69	$64.22	$55.70	17.9%

SOURCE: ACIL ALLEN ANALYSIS

Since the 2016-17 Draft Determination, the WEC for 2016-17 has increased by about two per cent – reflecting the increase in contract prices.

Overall, the changes in estimated WEC from 2015-16 to 2016-17 are much larger compared with changes in determinations from previous years. The estimated WEC for the NSLPs has increased by about $10-11/MWh, whereas the control load tariffs have increased by about $6/MWh. The increase in estimated WEC reflects the projected tightening of the demand-supply conditions in the Queensland region of the NEM in 2016-17 due to the increase in demand from in-field gas compression associated with the LNG export facilities, increasing gas prices, and no addition of new capacity. The projected increase in estimated WEC outcomes is consistent with the market modelling simulations and contract prices traded on the futures market.

The WEC for each tariff class is unlikely to increase (or decrease for that matter) by the same amount between one determination and the next – whether in dollar or percentage terms – due to their different load shapes and differences in how the load shapes are changing over time.

Section 4.2.1 shows that baseload contract prices have increased less between 2015-16 and 2016-17, compared with the peak and cap prices, and this is even more the case during the non-summer quarters. Hence, given that the control loads tend to be weighted more towards the off-peak periods and non-summer quarters (due to higher water heating loads in the cooler months), it seems reasonable that their respective WECs have not increased by the same extent as the WECs of the NSLPs.

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[12]) 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[13]
- Mandated LRET targets for 2016 and 2017 of 21,431 GWh and 26,031 GWh, respectively
- Published Renewable Power Percentage (RPP) for 2016 of 12.75 per cent
- Estimated RPP value for 2017 of 14.71 per cent[14]
- Binding Small-scale Technology Percentage (STP) for 2016 of 9.68 per cent
- Non-binding STP value for 2017 of 9.02 per cent[15]
- CER clearing house price for 2016 and 2017 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, the LRET legislation requires the CER to publish the RPP by 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.

12 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.

13 AFMA data includes weekly prices up to and including 21 April 2016.

14 2017 RPP value was estimated using liable electricity acquisitions implied in the non-binding STP value 2017, as published by CER.

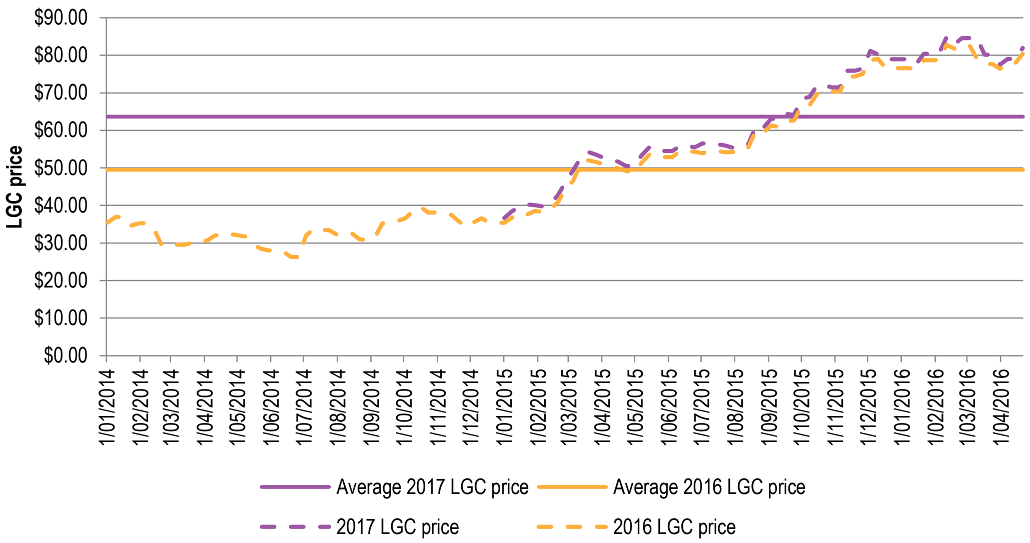
15 The non-binding 2017 STP estimate is based on the modelling prepared for CER for the 2016 STP, as published by CER.

ACIL Allen has estimated the average LGC price using forward looking weekly market prices for LGCs published by the Australian Financial Markets Association (AFMA) [16].

The LGC price used in assessing the cost of the scheme for 2016-17 is found by averaging the forward prices for the 2016 and 2017 calendar years, during the two years prior to the commencement of 2016 and 2017. This assumes that LGC coverage is built up over a two year period (see **Figure 4.13**). The average LGC prices calculated from the AFMA data are $49.48/MWh for 2016 and $63.62/MWh for 2017**.** These prices are higher than the Final Determination 2015-16 due to the recent surge in forward prices on the back of stalled construction of new projects incentivised by the LRET scheme. This is also the reason for higher average LGC prices since the Draft Determination 2016-17.

Over the past 24 months, LGC spot prices have been very volatile, ranging from $21 in June 2014 to $80 in February 2016. In 2014, LGC prices reached all-time lows, in part as a result of policy uncertainty during the Warburton RET review. In the first half of 2015, LGC prices firmed with bipartisan agreement to modify the LRET target to 33TWh and the subsequent passing of legislation in June 2015. Since mid-2015, LGC prices have continued to rise as a result of the current hiatus in new construction.

FIGURE 4.13 LGC PRICES FOR 2016 AND 2017 ($/LGC, NOMINAL)



SOURCE: AFMA AND ACIL ALLEN ANALYSIS

The 2017 RPP value of 14.71 per cent was estimated using the mandated target for 2017 and the total estimated electricity consumption implied in the non-binding STP value for 2017.

The 2016 RPP value of 12.75 per cent has been set by the CER and does not need to be estimated.

Key elements of the 2017 RPP estimation are shown in **Table 4.3**.

[16] *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 4.3 ESTIMATING THE 2017 RPP VALUE

	2017
Non-binding STP (CER)	9.02%
Projected STCs (CER)	15,960,000
Implied total estimated electricity consumption	176,940,133
LRET target	26,031,000
Estimated RPP using implied total estimated electricity consumption	14.71%

[a] Implied total estimated electricity consumption is 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 2016 and 2017 by multiplying the RPP values for 2016 and 2017 by the average LGC prices for 2016 and 2017, respectively. The cost of complying with the LRET in 2016-17 was found by averaging the calendar estimates.

Therefore, ACIL Allen estimates the cost of complying with the LRET scheme to be $7.83/MWh in 2016-17 as shown in **Table 4.4**.

TABLE 4.4 ESTIMATED COST OF LRET – 2016-17

	2016	2017	Cost of LRET 2016-17
RPP %	12.75%	14.71%	
Average LGC price ($/LGC, nominal)	$49.48	$63.62	
Cost of LRET ($/MWh, nominal)	$6.31	$9.36	$7.83

SOURCE: CER, AFMA AND ACIL ALLEN ANALYSIS

4.3.2 SRES

The cost of the SRES for calendar years 2016 and 2017 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 2016-17.

The STPs published by CER are as follows:

- Binding 2016 STP of 9.68 per cent (equivalent to 16.95 million STCs as a proportion of total estimated electricity consumption for the 2016 year)
- Non-binding 2017 STP of 9.02 per cent (equivalent to 15.96 million STCs as a proportion of total estimated electricity consumption for the 2017 year).

ACIL Allen estimates the cost of complying with SRES to be $3.74/MWh in 2016-17 as set out in **Table 4.5**.

TABLE 4.5 ESTIMATED COST OF SRES – 2016-17

	2016	2017	Cost of SRES 2016-17
STP %	9.68%	9.02%	
STC clearing house price ($/STC, nominal)	$40.00	$40.00	
Cost of SRES ($/MWh, nominal)	$3.87	$3.61	$3.74

SOURCE: CER, ACIL ALLEN ANALYSIS

4.3.3 Summary of estimated LRET and SRES costs

Adding these component costs gives a total cost requirement as set out in **Table 4.6**. This is compared to the costs from the Draft Determination 2016-17 and Final Determination 2015-16.

Since the Draft Determination 2016-17 and Final Determination 2015-16, total renewable energy costs have increased by 3 per cent and 33 per cent, respectively, largely driven by increasing LGC prices.

TABLE 4.6 TOTAL RENEWABLE ENERGY POLICY COSTS ($/MWH) – FINAL DETERMINATION 2016-17, DRAFT DETERMINATION 2016-17 AND FINAL DETERMINATION 2015-16

	Final Determination 2016-17	Draft Determination 2016-17	Final Determination 2015-16
LRET	$7.83	$7.27	$4.38
SRES	$3.74	$3.97	$4.34
Total	$11.57	$11.24	$8.72

SOURCE: ACIL ALLEN ANALYSIS

4.4 Estimation of other energy costs

The estimates of other energy costs for the Final 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), the National Transmission Planner (NTP) and the Energy Consumers Australia (ECA).

ECA is a relatively new cost category, approved by the Council of Australian Governments (COAG) Energy Council in May 2014 to promote the long term interests of energy consumers, in particular for residential customers and small business customers. The commencement date of the ECA was 30 January 2015 and AEMO is required to recover the funding for the ECA from market participants from 2015-16.

ECA requirements are measured in terms of connection points for small customers. It is not clear in AEMO's *Consolidated Draft Budget & Fees 2016-17* of the assumed number of connection points for small customers used in the cost estimate, therefore, ACIL Allen has used DNSP customer numbers, to estimate the cost of ECA requirements in $/MWh terms.

Based on fees in AEMO's *Consolidated Draft Budget & Fees 2016-17*, the total fee for 2016-17 is $0.48/MWh.

The breakdown of total fees is shown in **Table 4.7**.

TABLE 4.7 NEM MANAGEMENT FEE ($/MWH) – 2016-17

Cost category	Fees ($/MWh)
Operational expenditure (admin, registration, etc.)	$0.38
FRC - electricity	$0.055
NTP - electricity	$0.016
ECA - electricity	$0.026
Total NEM management fees	$0.48

SOURCE: ACIL ALLEN ANALYSIS OF AEMO, AER STATE OF THE ENERGY MARKET 2015

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 2016-17, the cost of ancillary services is estimated to be $0.33/MWh.

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 inputs in **Table 4.8** for each season for Energex NSLP gives an estimated MCL of $6,216.

TABLE 4.8 AEMO PRUDENTIAL COSTS – 2016-17

Factor	Summer	Winter	Shoulder
Load Weighted Expected Price	$87.78	$54.24	$56.40
Participant Risk Adjustment Factor	1.2972	1.2354	1.1952
OS Volatility factor	1.7	1.3	1.46
PM Volatility factor	3.07	1.72	1.89
Loss Factor	1.065	1.065	1.065
OSL	$7,937	$3,572	$4,035
PML	$1,587	$714	$807
MCL	$9,525	$4,286	$4,842
Average MCL		$6,216	

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 $6,216/42 = $148/MWh.

The cost of funding a bank guarantee for the MCL associated with the single MWh is assumed to be a 2.5 percent annual charge for 42 days or 2.5%*(42/365) = 0.288 percent. Applying this funding cost to the single MWh charge of $148 gives $0.43/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 costs. The current money market rate is around 2.0 percent. 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 8.0 percent on average for a base contract
— the intra monthly spread charge currently set at $8,500 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 $53.74 and applying the above factors gives an average initial margin for each quarter of $18,315 for a 1 MW quarterly contract. Dividing this by the average hours in a quarter then gives an initial margin of $8.36 per MWh. Assuming a funding cost of 8.47[17] percent but adjusted for an assumed 2.0 percent return on cash lodged with the clearing house gives a net funding cost of 6.47 percent. Applying 6.47 percent to the initial margin per MWh gives a prudential cost for hedging of $0.54/MWh.

[17] QCA provided ACIL Allen with the funding cost to be used in the analysis.

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.

Total prudential costs

Adding the AEMO and hedge prudential costs gives a total prudential requirement as set out in **Table 4.9**.

TABLE 4.9 TOTAL PRUDENTIAL COSTS ($/MWH) - 2016-17

Cost category	Cost
AEMO pool	$0.43
Hedge	$0.56
Total	$0.99

SOURCE: ACIL ALLEN ANALYSIS

4.4.4 Summary of estimated total other costs

Adding these component costs gives a total other cost requirement as set out in **Table 4.10** and is compared to the costs from the Draft Determination 2016-17 and Final Determination 2015-16.

TABLE 4.10 TOTAL OF OTHER COSTS ($/MWH) – FINAL DETERMINATION 2016-17, DRAFT DETERMINATION 2016-17 AND FINAL DETERMINATION 2015-16

Cost category	Final Determination 2016-17	Draft Determination 2016-17	Final Determination 2015-16
NEM management fees	$0.48	$0.49	$0.47
Ancillary services	$0.33	$0.38	$0.36
Hedge and pool prudential costs	$0.99	$0.93	$1.03
Total	$1.80	$1.80	$1.86

SOURCE: ACIL ALLEN ANALYSIS

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 (DLFs) 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 marginal loss factors (MLFs) for the Energex and Ergon Energy east zone Transmission Node Identities (TNIs). This analysis resulted in a transmission loss factor of 1.007 for Energex and 1.023 for the Ergon Energy east zone. These estimates are based on final MLFs 2016-17 as published by AEMO on 1 April 2016, weighted by the 2014-15 energy for the TNIs.

The DLFs by settlement class for the Energex area and the Ergon energy east zone are taken from the Final Distribution Loss Factors for 2016-17 as published by AEMO on 31 March 2016. The DLFs show marginal differences from the DLFs used in the Final Determination for 2015-16, the largest being an increase in Ergon Energy - NSLP - SAC demand and street lighting, an increase of 0.012. The reason for this increase in the DLF is not discussed in the AEMO release.

The estimation of transmission and distribution loss factors for the settlement classes to be used in calculating energy costs for the Final Determination are shown in **Table 4.11**. The weighted MLFs are based on final estimates of MLFs for 2016-17 published by AEMO. Changes in MLFs between 2015-16 and 2016-17 are minimal, with the exception of Ergon Energy MLFs, which are lower in 2016-17. As observed by AEMO in their report, this is due to a reduction in MLFs at connection points in northern and central Queensland.

TABLE 4.11 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	1.058	1.007	1.065
Energex - Control tariff 9000	1.058	1.007	1.065
Energex - Control tariff 9100	1.058	1.007	1.065
Ergon Energy - NSLP - SAC HV, CAC and ICC	1.028	1.023	1.052
Ergon Energy - NSLP - SAC demand and street lighting	1.095	1.023	1.120

DATA SOURCE: ACIL ALLEN ANALYSIS BASED ON QUEENSLAND TNI ENERGY FOR 2014-15, FINAL MLFS FOR 2016-17 AND ENERGEX AND ERGON ENERGY EAST ZONE DLFS FOR 2016-17 FROM AEMO.

For the Final Determination for 2016-17 ACIL Allen has applied the same methodology as used in previous years so that it aligns with the application of the MLFs and DLFs used by AEMO.

As described by AEMO[18], 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)*

4.6 Summary of estimated energy costs

Drawing together the analyses and estimates from the previous sections of this report, ACIL Allen's estimates of the 2016-17 total energy costs (TEC) for the Draft Determination for each of the settlement classes are presented in **Table 4.12**.

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

TABLE 4.12 ESTIMATED TEC FOR 2016-17 FINAL DETERMINATION

Settlement class	WEC at Qld reference node ($/MWh)	Renewable energy costs at Qld reference node ($/MWh)	Other costs Qld reference node ($/MWh)	Total transmission and distribution loss factor (MLF x DLF)	Network losses ($/MWh)	TEC at the customer terminal ($/MWh)	Change from 2015-16 Final Determination ($/MWh)	Change from 2015-16 Final Determination (%)
Energex - NSLP - residential and small business	$75.32	$11.57	$1.80	1.065	$5.76	$94.45	$15.31	19.35%
Energex - Control tariff 9000 (31)	$42.31	$11.57	$1.80	1.065	$3.62	$59.30	$9.59	19.29%
Energex - Control tariff 9100 (33)	$56.15	$11.57	$1.80	1.065	$4.52	$74.04	$9.11	14.03%
Energex - NSLP - unmetered supply	$75.32	$11.57	$1.80	1.065	$0.00	$94.45	$15.31	19.35%
Ergon Energy - NSLP - SAC HV, CAC and ICC	$65.69	$11.57	$1.80	1.052	$4.11	$83.17	$12.52	17.72%
Ergon Energy - NSLP - SAC demand and street lighting	$65.69	$11.57	$1.80	1.120	$9.49	$88.55	$14.12	18.97%

SOURCE: ACIL ALLEN ANALYSIS

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