ACIL ALLEN CONSULTING

REPORT TO
QUEENSLAND COMPETITION AUTHORITY

9 MAY 2017

ESTIMATED ENERGY COSTS

2017-18 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 2017-18 RETAIL TARIFFS: FINAL DETERMINATION, ACIL ALLEN, MAY 2017

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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 2017-18.

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), and the Consultancy Terms of Reference (TOR) provided by the QCA, 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 2017-18. 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, 2015-16 and 2016-17 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 2017–18* (February 2017), where those submissions refer to the cost of energy in regulated retail electricity prices.

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 2017 to 30 June 2018.

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, 2015-16, and 2016-17 Determinations (refer to ACIL Allen's report for the 2014-15 Draft Determination[1] and the 2014-15 Final Determination[2] 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 price risk by entering into electricity contracts with prices represented by the observable futures

[1] http://www.qca.org.au/getattachment/4cb8b436-7b50-4328-8e27-13f51a4d021c/ACIL-Allen-Estimated-Energy-Costs-2015-15-Retail-T.aspx
[2] http://www.qca.org.au/getattachment/9be567a8-92e2-4d53-85f0-3781e4f8662f/ACIL-Allen-Final-Report-Estimated-Energy-Costs-for.aspx

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, 2015-16 and 2016-17 reviews, ACIL Allen continues to use the market hedging approach for estimating the WEC for 2017-18.

We have utilised our:

- stochastic demand model to develop 46 weather influenced simulations of hourly demand traces for each of the tariff profiles – using temperature data from 1970-71 to 2015-16 and demand data for 2011-12 to 2015-16
- stochastic outage model to develop 11 hourly power station availability simulations
- energy market models to run 506 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 2017-18 provided in AEMO's 2016 National Electricity Forecasting Report (NEFR) continues to be the most reasonable demand forecast for the purposes of this analysis. However, unlike the Draft Determination, ACIL Allen no longer assumes the closure of the 600 MW base load Portland aluminium smelter in August 2017 in Victoria. Instead, the demand forecast assumes the continuation of operations at Portland throughout the 2017-18 determination period.

No changes to the supply side assumptions have been made since the Draft Determination.

Our modelling suggests that the continued operation of Portland in 2017-18, and hence assuming demand in Victoria is on average 600 MW higher in the Final Determination than in the Draft Determination, results in a substantial increase wholesale prices in Victoria. Further, this change in the demand-supply balance, is projected to increase wholesale spot prices in Queensland by about $8/MWh in 2017-18, all other things equal, relative to 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 TFS, 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 2017 and 2018 calendar years, with the costs averaged to estimate the 2017-18 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 and TFS
- currently legislated LRET targets (in GWh) for 2017 and 2018
- the Renewable Power Percentage (RPP) for 2017[3] as published by the CER

[3] The CER is obligated to publish the official RPP for the 2017 compliance year by 31 March 2017 in accordance with Section 39 of the Renewable Energy (Electricity) Act 2000

— estimate of the RPP for 2018
— the binding Small-scale Technology Percentage (STP) for 2017[4] under the SRES as published by the CER
— estimate for the STP for 2018 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.

ACIL Allen undertook a separate analysis of the Retail Operating Cost and Margin ROC and ROM for the QCA for the 2016-17 Determination, and has been engaged to assist the QCA with an update for the 2017-18 Determination, 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 2017-18 MLFs and DLFs published by AEMO on 31 and 30 March 2017 respectively.

[4] The CER is obligated to publish the official STP for the 2017 compliance year by 31 March 2017 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.

3 RESPONSES TO SUBMISSIONS TO DRAFT DETERMINATION

3.1 Introduction

The QCA forwarded to ACIL Allen a total of nine submissions in response to its Draft Determination. ACIL Allen reviewed the submissions to identify issues that required our consideration. A summary of the review is shown below in Table 3.1. The following sections in this chapter address each of the relevant issues raised in the submissions.

TABLE 3.1 REVIEW OF ISSUES RAISED IN SUBMISSIONS IN RESPONSE TO DRAFT DETERMINATION

Id	Stakeholder	Wholesale energy costs	Contract prices / hedge model	Renewable energy policy costs	NEM fees	Prudential costs	Energy losses
1	Australian Sugar Milling Council	Nil	Nil	Nil	Nil	Nil	Nil
2	Canegrowers ISIS Ltd	Nil	Nil	Nil	Nil	Nil	Nil
3	CANEGROWERS	Yes	Nil	Yes	Nil	Yes	Nil
4	Chamber of Commerce and Industry Queensland (CCIQ)	Nil	Nil	Nil	Nil	Nil	Nil
5	Energy Queensland	Yes	Yes	Yes	Nil	Nil	Nil
6	Queensland Consumers' Association	Nil	Nil	Nil	Nil	Nil	Nil
7	Queensland Council of Social Service (QCOSS)	Yes	Nil	Nil	Nil	Nil	Nil
8	Origin Energy	Nil	Yes	Nil	Nil	Nil	Nil
9	Cotton Australia	Nil	Nil	Nil	Nil	Nil	Nil

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

SOURCE: ACIL ALLEN ANALYSIS OF QCA SUPPLIED DOCUMENTS

3.2 Overall approach

A number of the submissions supported the continuation of ACIL Allen's approach for the purposes of consistency. For example, Energy Queensland note on page 2 of their submission:

Energy Queensland supports a market based approach for determining energy costs.

Additionally, the Queensland Council of Social Service (QCOSS) notes on page six of their submission:

In regard to energy (generation) costs, QCOSS is not aware of any new information which would suggest alternative approaches to those used in the 2016-17 price determination might be more appropriate. QCOSS supports the QCA's estimation of energy costs for 2017-18 being based on the application of the same methodology that was used in 2016-17.

3.3 Inclusion of updated data in analysis for the Final Determination

A number of submissions made note of the need to include updated data for the Final Determination. For example, Energy Queensland on page two of their submission note:

We note that the Draft Determination has accounted for energy costs up to November2016. However, given the very high prices experienced between December 2016 and March 2017 we anticipate that this will result in a higher energy cost allowance.

And Origin Energy on page one of their submission note:

It is noted that the QCA's Draft Determination only includes energy cost data relevant to November 2016. It is understood the Final Determination will include updated wholesale energy cost data.

As the QCA would be aware, the forward price for electricity has risen considerably since November 2016. It is anticipated that the energy costs included in the Final Determination will be considerably higher than that set out in the Draft Determination.

As with previous final determinations, the 2017-18 Final Determination takes into account market information made available since the Draft Determination. This includes:

— Updated contract prices
— Updated LGC prices
— Updated input assumptions to the market simulations.

3.4 Estimation mechanisms

Energy Queensland on page two of their submission suggest that the recent increase in price outcomes observed in the market highlights a deficiency in the methodology :

Recent high prices in the spot and contract market has again highlighted the limitations in the methodology used for determining energy costs when only using exchange information as the key input to the calculations. This is especially evident in the Large Renewable Energy Target (LRET) costs.

ACIL Allen does not agree with this suggestion. The methodology takes into account the latest information available at the time of the analysis. Extension of the cut-off date for contract price data to April 2017 for the Final Determination, two months before the commencement of the 2017-18 determination year, minimises the exclusion of further contract price data changes on a volume weighted basis. Further, the methodology utilises exchange based contract price data which is verified by OTC contract price data. This has been the approach for each determination and has consistently shown a very close alignment between the two sources of contract price data. However, for the 2017-18 Final Determination, ACIL Allen has utilised LGC price data from TFS to supplement the previous LGC price data from AFMA (as discussed in more detail in section **4.3.1**).

3.5 Cost structure

CANEGROWERS suggest that the Ergon NSLP should be used to calculate the energy costs and prudential costs, on pages one and three of their submission:

In calculating the underlying cost structure, QCA has applied Energex network costs and applied these to the Ergon network. It has not taken account of the fact that many of the costs in the Energex area do not apply in the Ergon area. A significant factor is that the Energex load profile is peakier than the Ergon *load profile. This means that the cost of energy in Energex load profile is higher than that faced by Ergon.*

CANEGROWERS recommends the QCA calculate prudential costs based on the Ergon NSLP, not the Energex NSLP.

ACIL Allen has been engaged to estimate the wholesale energy costs for each profile, including the Ergon NSLP, as provided in this report. CANEGROWERS' suggestion is a matter for the QCA to consider, as we have not been engaged to provide advice on the manner in which these estimates are used in the determined tariffs.

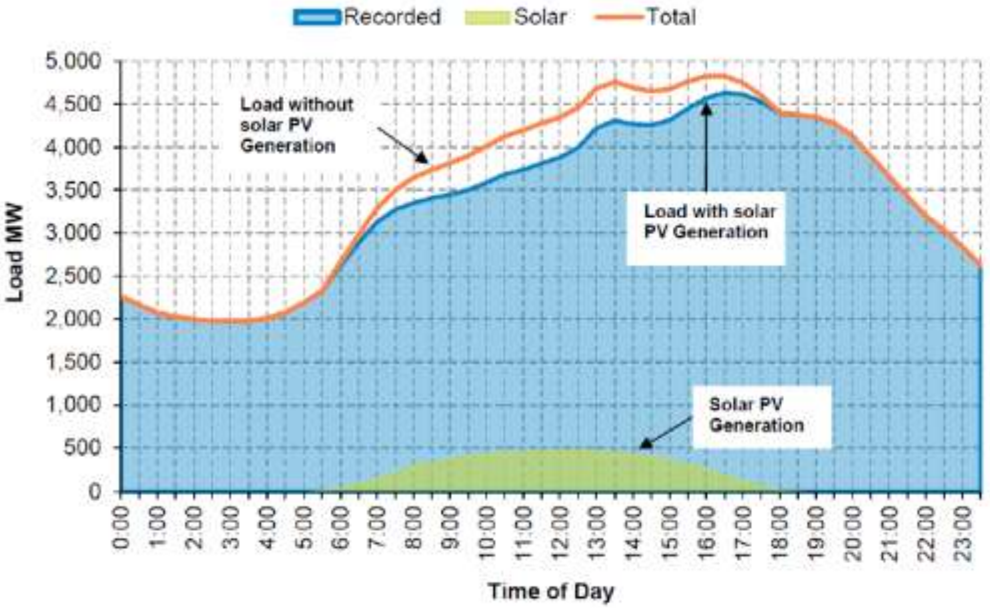
CANEGROWERS, on page two of their submission, disagree with our suggestion that further rooftop solar PV installation will not have an impact on the peak demand of the Energex NSLP:

In the Draft Determination QCA reports "Over the past few years, the Energex NSLP has become peakier due to increased solar generation reducing daytime demand but having no effect on the evening peak demand. Figure 8 shows how the NSLP has become peakier over time". This observation is at odds with the information contained in Energex's Distribution Annual Planning Report, 2016/17-2020/21, Volume 1. ... The Energex NSLP shows that even on a cloudy day, PV is materially reducing the system peak. This is the opposite to the claim made in the QCA Draft Determination.

CANEGROWERS reproduce the graph in Figure 3.1 in their submission, which is included in the Energex Distribution Annual Planning Review, which shows the time of day demand for the Energex system on 1 February 2016. ACIL Allen agrees with CANEGROWERS – rooftop solar PV has reduced the Energex system wide peak demand. However, our comment refers to the Energex NSLP, which is a subset of the Energex total system demand. Figure 3.2 shows the time of day NSLP demand for the same date – 1 February 2016. The graph clearly shows that when "adding back" the estimated generation from rooftop solar PV, the peak demand would have been the same given it occurs at around 7:00pm – 7:30pm. It is important to remember that the NSLP excludes large (commercial) consumers with interval meters, and hence has a different shape to the total Energex system demand.

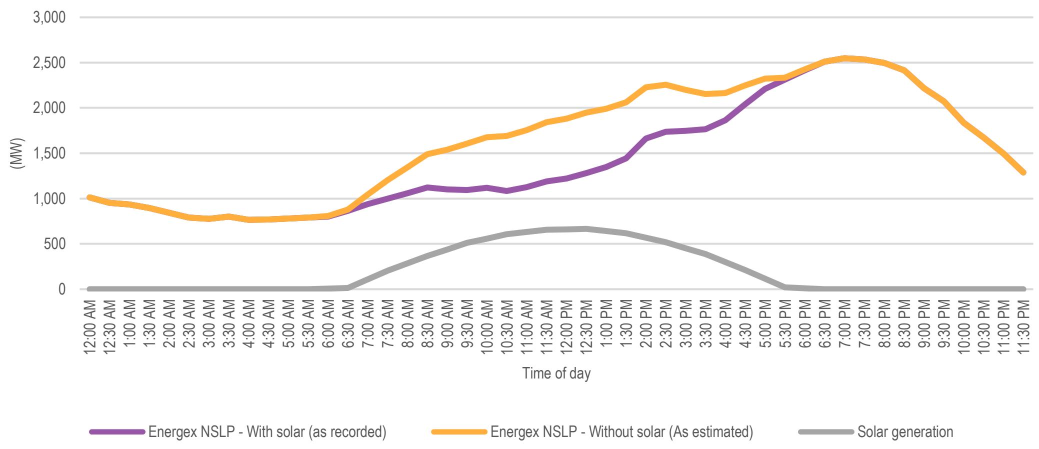
Regardless, our comment is more about the impact of *further* installations of rooftop solar PV, beyond the current installed stock (given that the current stock has already had its impact). Figure 3.2 shows that the NSLP peaks in summer well into the evening, and hence *further* installations will not have an impact on the peak demand but will continue to hollow out demand during daylight hours.

FIGURE 3.1 ENERGEX SYSTEM DEMAND – SOLAR PV IMPACT, 1 FEBRUARY 2016



SOURCE: ENERGEX DAPR 2016/17-2020/21

FIGURE 3.2 ENERGEX NSLP – ESTIMATED SOLAR PV IMPACT – 1 FEBRUARY 2016



SOURCE: ACIL ALLEN ANALYSIS OF AEMO DATA

3.6 LGC costs

CANEGROWERS on page three of their submission re-introduce the argument that a prudent retailer will have entered into long term contract for LGCs and that these should be taken into account:

QCA proposes to increase the charges for LGCs at a punitive 49.9% higher in 2017-18 than in 2016-17. This begs the question for which retailers in the Ergon distribution system have the proposed charges been calculated, a new marginal retailer or an incumbent retailer?

The charges identified appear to be set for a marginal retailer that has no long-term offtake contracts in place and has not made an investment in renewable energy capacity. Aware of the Australia wide policy preference for renewable energy generation and a stronger policy push towards renewable energy in Queensland, an efficient prudent retailer with evergreen customer contracts (Ergon Retail) would have managed this risk by being long with respect to renewables.

Just as retailers in the Energex network have managed their LGC price exposure, as the long-term incumbent retailer in regional Queensland, to manage its exposure Ergon retail will have longstanding purchases of Large-scale Renewable Energy Target (LRET) and Small-scale Renewable Energy Scheme (SRES) certificates. The QCA approach to setting the LGC component of prices is likely to deliver Ergon a windfall trading gain in the purchase of its certificates.

CANEGROWERS recommends the QCA calculates the LGC component of prices based on the behaviour of an efficient long term incumbent retailer.

This argument has been raised in previous determinations by retailers. However, retailers raise this issue when spot and futures prices are *less* than the levelised cost of electricity of new investment thermal or renewable generation. In this instance, given that spot and futures prices have increased to levels *greater* than the levelised cost of electricity of new generation, the suggestion has come from the consumer's side.

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.

ACIL Allen on page 27 in its report for the 2014-15 Final Determination[5] addressed this issue in detail. 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. Certainly, ACIL Allen is not of the view of "cherry-picking" the approach simply because market prices have increased or decreased to be above or below the levelised cost of electricity of new entrant generation.

[5] 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 described in Chapter **2** and summarise the estimates of each component of the Total Energy Cost (TEC) for each of the tariff classes for 2017-18.

4.1.1 Historic energy cost levels

Figure 4.1 shows the average time of day pool (spot) price for the Queensland region of the NEM, and the actual average time of day load profiles for Queensland, tariffs 31, 33 and 11, and the Ergon NSLP for the past five years. The graphs are useful in understanding the dynamics of the absolute and relative wholesale electricity price changes in the tariffs.

It is worth noting the uplift in spot prices in 2015-16, and again to date in 2016-17, across most periods of the day, compared with 2014-15. This is a result of an increase in the underlying demand in Queensland due to the ramping up of production associated the LNG export facilities in Gladstone, as well as an increase in gas prices into gas fired generators (as shown by the ramp up in gas prices on AEMO's short term trading market (STTM) in Figure 4.2).

Further, it can be seen that to date in 2016-17 prices are noticeably higher and more volatile during the evening periods – this is largely due to the recent strong price outcomes in the protracted summer period driven by strong gas prices over the same period, as well as reduced output from some of the NSW coal fired power stations due to coal supply constraints.

In relation to each load profile, we note the following:

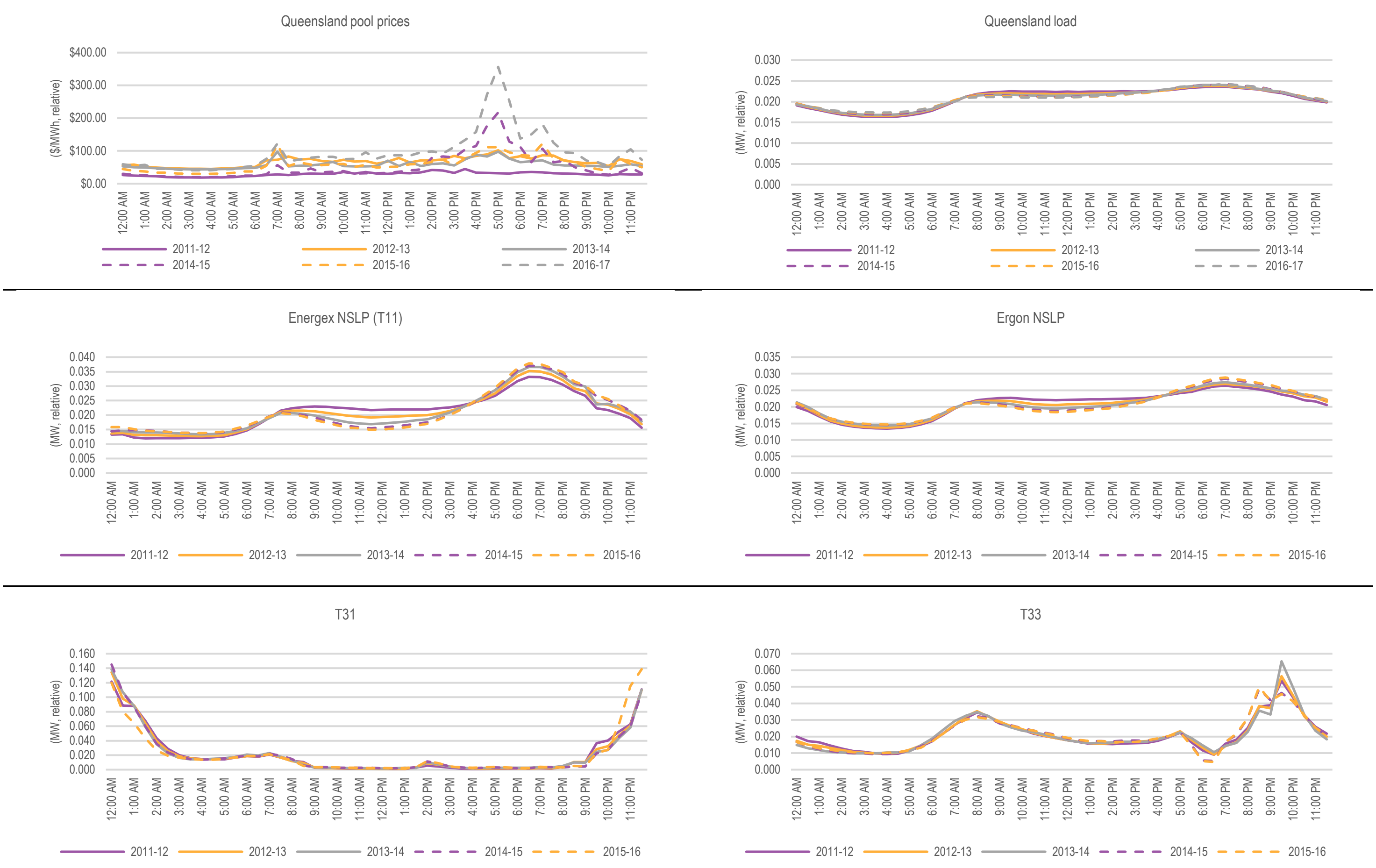
— The annual time of day price profile has been volatile over the past five years – with the overall level and shape of the price profile changing from one year to the next. For example, in 2011-12 the time of day profile was very flat compared with 2014-15. In 2012-13 and 2013-14, prices increased largely because of the carbon tax. Prices have generally peaked in the afternoon and evening, whereas in some years there is also a morning peak. In short, the profile of prices varied from one year to the next – noting that these are the annual profiles (seasonal profiles are even more variable over time).

— The load profile of tariff 31 has been relatively consistent from one year to the next since 2011-12 – ramping up from about 9:30 pm, peaking at about midnight and then ramping down to about 3:00 am. This is inversely correlated with the price profile – with load higher at times of lower spot prices. This has resulted, on average, in a relatively low wholesale energy cost for tariff 31, compared with the other tariffs.

— The load profile of tariff 33 has been relatively consistent from one year to the next for most parts of the day. However, there was some volatility between 5:30 pm and 10:30 pm over the past few years. The load exhibits a morning peak at around 8:00 am – and prices also experience uplift around that time. The load also exhibits an evening peak at around 9:30 pm – but this varied from year to year (note that in 2014-15 and 2015-16 it tends to peak around 8:30 pm). Compared with tariff 31, the load profile of tariff 33 is weighted slightly more towards the daylight hours and the evening peak, and hence it is not surprising that its wholesale energy costs are higher than those of tariff 31.

— Over the past few years, the Energex NSLP load profile (tariff 11), and to a similar degree, the Ergon NSLP, have experienced a carving out of load during daylight hours with the increased penetration of rooftop solar PV. This results in the load profile becoming peakier over time. The Energex NSLP load profile has a higher weighting towards the peak periods – particularly the evening peak and hence it is not surprising that the NSLP has the highest wholesale energy cost out of the profiles.

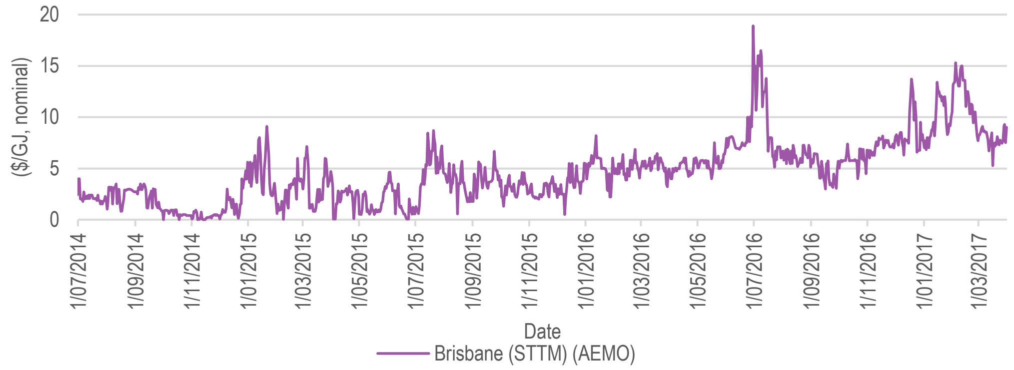
FIGURE 4.1 ACTUAL AVERAGE TIME OF DAY QLD WHOLESALE SPOT PRICE ($/MWH, NOMINAL) AND LOAD PROFILE (MW, RELATIVE) – 2011-12 TO 2016-17



Note: The term relative MW means the loads for each tariff and year have been scaled so they sum to one. This removes differences in absolute scale between the different tariffs and changes in absolute size over time. This is an appropriate representation of the loads since it is the relative shape of the load profile, not its absolute size, which determines its wholesale energy cost. Values for 2016-17 based on data up to 18 April 2017. Insufficient data available for 2016-17 for tariff classes due to lag in release of data by AEMO.

SOURCE: ACIL ALLEN ANALYSIS OF AEMO DATA

FIGURE 4.2 DAILY STTM GAS PRICE ($/GJ, NOMINAL) - BRISBANE

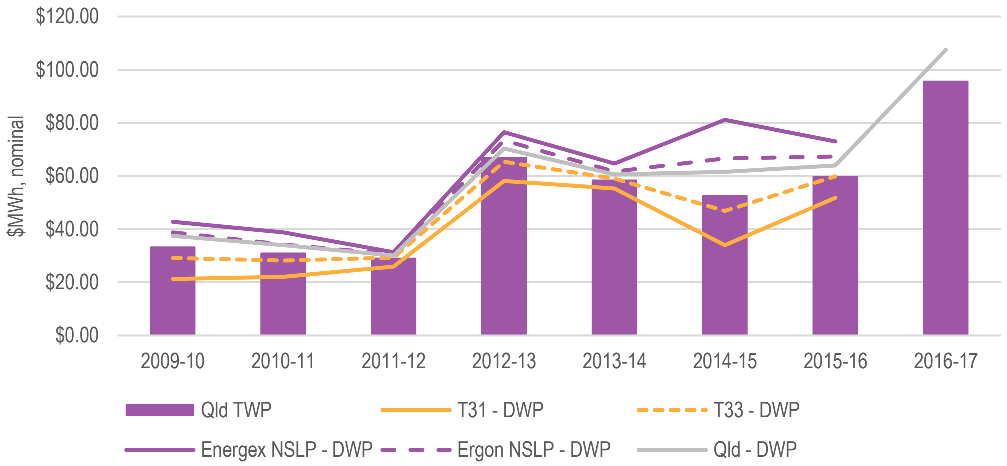


SOURCE: AEMO DATA

Figure 4.3 shows the actual annual demand weighted spot price (DWP) for each of the tariffs compared with the time weighted average spot price in Queensland (TWP) over the past seven years. As expected, the DWPs for tariffs 31 and 33 are below the DWP for the NSLPs in each year, with tariff 31 having the lowest price. Although the rank order in prices by tariff has been consistent in each year, the dollar value differences between the prices has varied from one year to the next. For example, in 2011-12, the flat half-hourly price profile resulted in the three tariffs having relatively similar wholesale spot prices. However, in 2014-15, the increased price volatility across the afternoon period resulted in the NSLP spot price diverging away from tariff 31 and 33. Conversely, the increase in off-peak spot prices in 2015-16 has lifted the DWP of tariff 31 and 33 up towards that of the NSLP.

The increase in spot price outcomes to date in 2016-17 is quite apparent, with prices on an average time weighted basis of about $95/MWh – compared with $60/MWh in 2015-16 (representing an increase of just under 60 per cent).

FIGURE 4.3 ACTUAL ANNUAL AVERAGE DEMAND WEIGHTED PRICE ($/MWH, NOMINAL) BY TARIFF AND QUEENSLAND TIME WEIGHTED AVERAGE PRICE ($/MWH, NOMINAL) – 2009-10 TO 2015-16



Note: Values reported are spot (or uncontacted) prices. Values for 2016-17 based on data up to 18 April 2017. Insufficient data available for 2016-17 for tariff classes due to lag in release of data by AEMO.

SOURCE: ACIL ALLEN ANALYSIS OF AEMO DATA

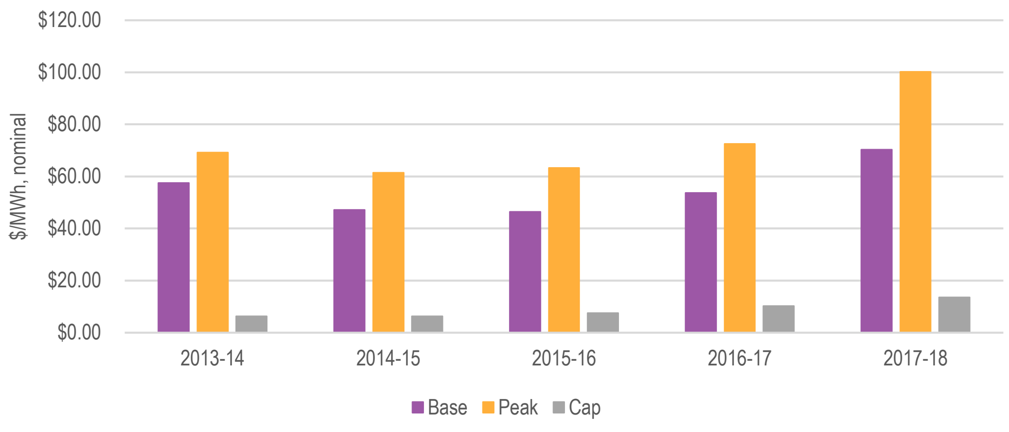
The volatility of spot prices (timing and incidence) in the Queensland region of the NEM provides the incentive to a retailer to hedge their load, since hedging of the loads reduces a retailer's exposure to the volatility. The suite of contracts (as defined by base/peak, swap/cap and quarter) available to retailers does not really change from one year to the next. However, the movements in contract price is the key contributor to movements in the estimated wholesale energy costs of the different tariffs year on year, as is shown in Figure 4.4.

The market modelling undertaken by ACIL Allen, and reported in this chapter, aligns with the market's expectations of price outcomes in 2017-18. Compared with the 2016-17 Final Determination, futures contract prices for 2017-18, on a trade weighted basis, have increased by:

— About $16.55/MWh for base contracts
— About $27.67/MWh for peak contracts
— And about $3.26/MWh for cap contracts.

The market is clearly expecting a strong increase in price outcomes in 2017-18, particularly across the peak periods due to the closure of Hazelwood power station and continued operation of the Portland smelter. Further, gas prices continue to increase – such that the short run marginal costs (SRMCs) of gas fired CCGTs are projected to increase by about $5-$10/MWh between 2016 and 2018, and the SRMCs of gas fired peaking plant are projected to experience a $10-$20/MWh increase.

FIGURE 4.4 ANNUALISED QUARTERLY BASE, PEAK AND CAP CONTRACT PRICES ($/MWH) – FINAL DETERMINATION 2017-18 AND PREVIOUS FINAL DETERMINATIONS



SOURCE: ACIL ALLEN

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 3 April 2017.

Table 4.1 shows the estimated quarterly swap and cap contract prices for the 2017-18 Final Determination and compares them with the estimates under the Draft Determination 2017-18 and the Final Determination for 2016-17.

TABLE 4.1 ESTIMATED CONTRACT PRICES ($/MWH)

	Q3	Q4	Q1	Q2
Final Determination 2017-18				
Base	$63.13	$66.46	$89.73	$62.33
Peak	$78.56	$89.23	$142.45	$91.62
Cap	$6.87	$13.47	$27.41	$6.75
Draft Determination 2017-18				
Base	$50.84	$57.62	$77.43	$50.83
Peak	$72.17	$84.55	$118.72	$74.26
Cap	$5.60	$12.08	$23.04	$5.92
% change from Draft Determination 2017-18				
Base	24%	15%	16%	23%
Peak	9%	6%	20%	23%
Cap	23%	12%	19%	14%
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
% change from Final Determination 2016-17				
Base	41%	23%	26%	38%
Peak	45%	31%	28%	60%
Cap	43%	29%	31%	35%

SOURCE: ACIL ALLEN ANALYSIS USING ASX ENERGY DATA UP TO 3 APRIL 2017

Trade weighted contract prices for 2017-18 are on average 36 per cent higher than for 2016-17 due to an expected reduction in plant capacity and gas-fired generators offering capacity into the market at higher prices:

— On 3 November 2016, Engie formally announced the closure of Hazelwood in Victoria (1,640 MW) from April 2017. With no near-term replacement capacity planned, futures prices have significantly increased in all regions as a result.

— 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 in power stations are on the rise. In some cases, this has led to planned plant closures, for example, Smithfield power station in New South Wales (170 MW), which is to close after July 2017, when its gas supply contract ends.

Trade weighted contract prices for the Final Determination 2017-18 are on average around 17 per cent higher than the Draft Determination 2017-18. There are some reasons that may explain this increase:

— At the time of the Draft Determination in November 2016, the futures market had not completely factored in the impact of the Hazelwood closure, which was only formally announced less than a month prior to the cut-off date for the Draft Determination.

— Further, the futures market had assumed and factored in, to some degree, the closure of the Portland smelter load in the lead up to the Draft Determination. However, since the Draft Determination, there is now certainty that the smelter will continue to operate in 2017-18, with the Victorian and federal governments announcing a package on 19 January 2017 to extend the operation of the smelter, which has certainly increased futures prices, even in Queensland.

— Electricity demand reached a level of 9,369 MW on 12 February 2017, which aligns reasonably well with the forecast of peak demand published in the 2016 NEFR given the high temperature conditions experienced in Queensland in February 2017. However, Queensland also experienced a protracted summer in 2016-17, with a record number of consecutive days above 30 degrees in Brisbane for example, which resulted in strong spot price outcomes. It is likely that the futures market for the 2017-18 determination year has been influenced by these recent events – particularly the futures price for Q1 2018.

— Futures continued to trade heavily at these higher prices, since the Draft Determination, thereby pushing up the trade-weighted average price for the Final Determination.

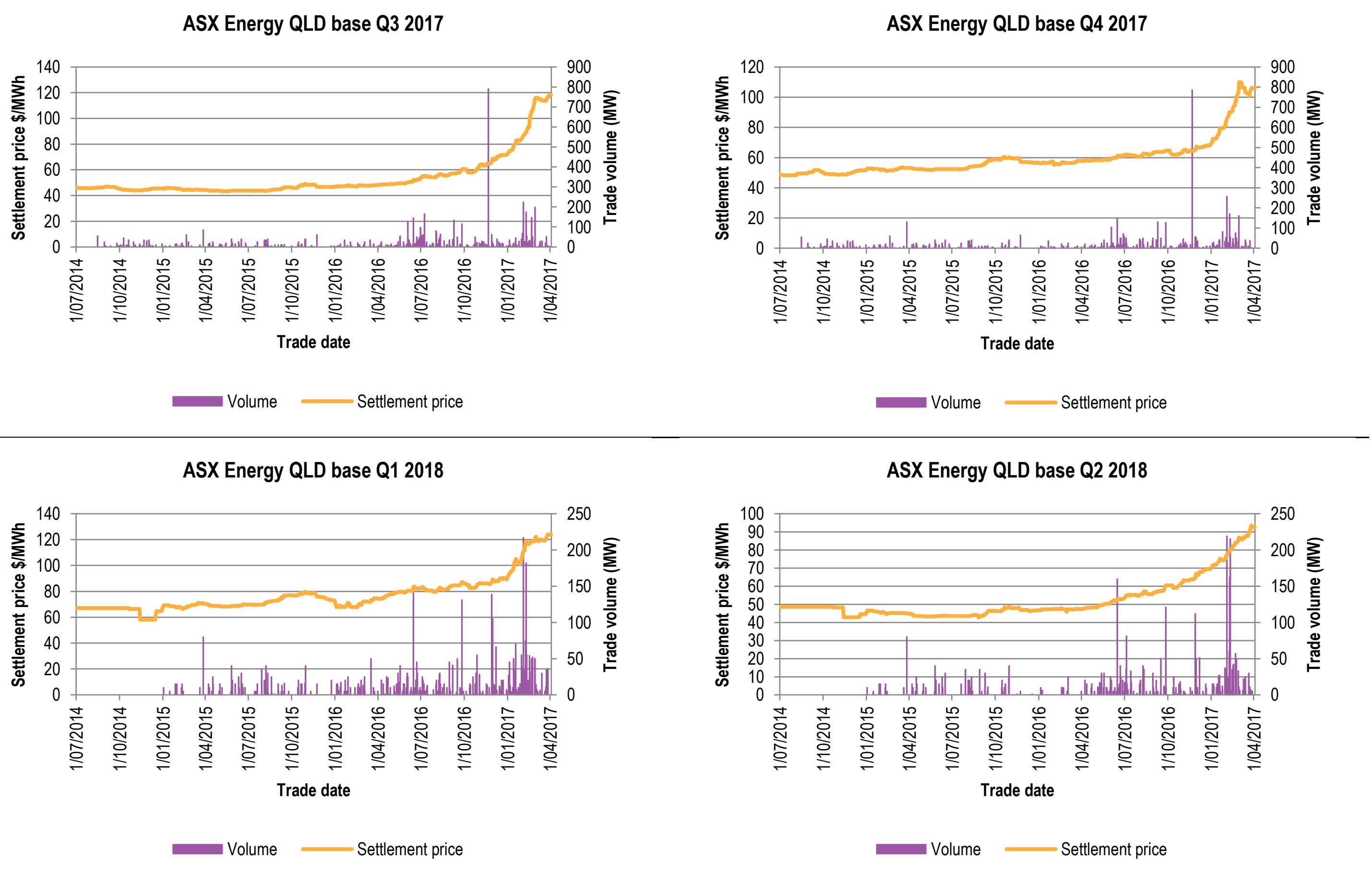
The following charts show daily settlement prices and trade volumes for ASX Energy quarterly base futures, peak futures and cap contracts up to 3 April 2017. It is worth noting that although contract prices have increased since the Draft Determination, they have stabilised or even decreased marginally in the last month of the data collection period.

Base futures have traded strongly, with total volumes of 7,105 MW (Q3 2017), 6,361 MW (Q4 2017), 4,766 MW (Q1 2018), and 3,916 MW (Q2 2018).

Peak futures have also traded strongly with 82 MW (Q3 2017), 117 MW (Q4 2017), 50 MW (Q1 2018) and 55 MW (Q2 2018).

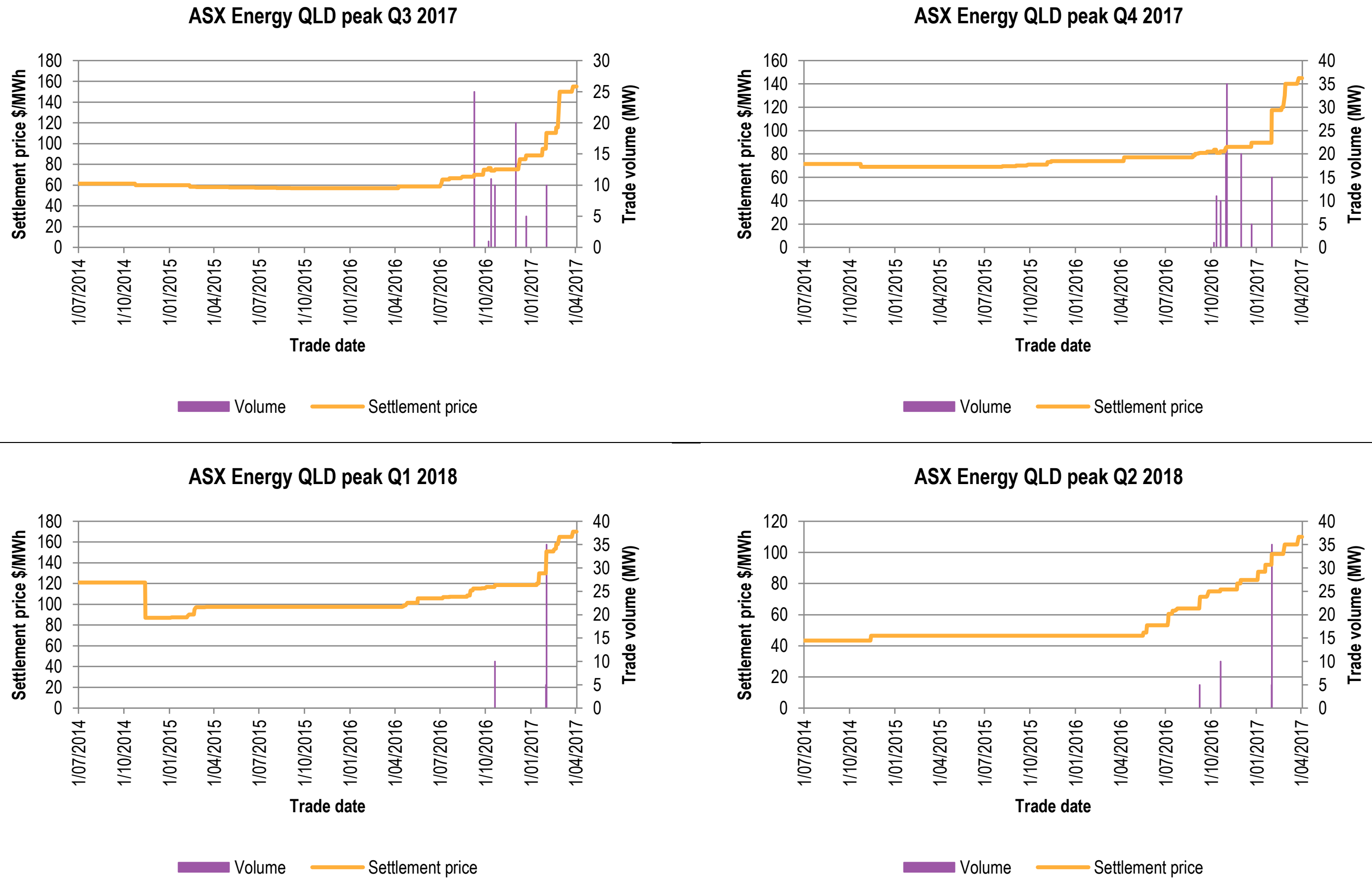
Cap contract trade volumes have also traded strongly with 1,195 MW (Q3 2017), 1,003 MW (Q4 2017), 902 MW (Q1 2018) and 543 MW (Q2 2018).

FIGURE 4.5 TIME SERIES OF TRADE VOLUME AND PRICE – ASX ENERGY QUEENSLAND BASE FUTURES



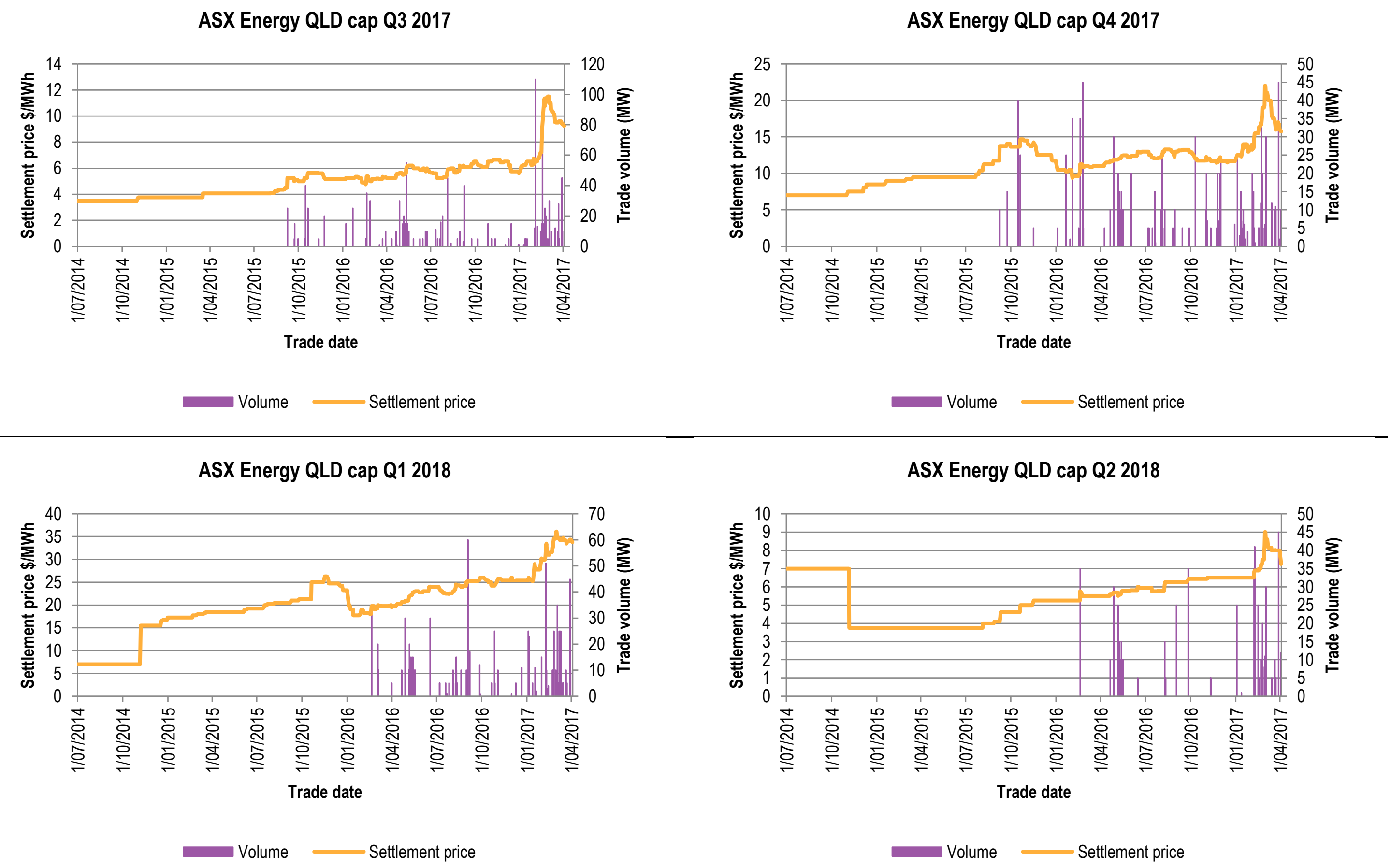
SOURCE: ASX ENERGY DATA UP TO 3 APRIL 2017

FIGURE 4.6 TIME SERIES OF TRADE VOLUME AND PRICE – ASX ENERGY QUEENSLAND PEAK FUTURES



SOURCE: ASX ENERGY DATA UP TO 3 APRIL 2017

FIGURE 4.7 TIME SERIES OF TRADE VOLUME AND PRICE – ASX ENERGY QUEENSLAND $300 CAP CONTRACTS



SOURCE: ASX ENERGY DATA UP TO 3 APRIL 2017

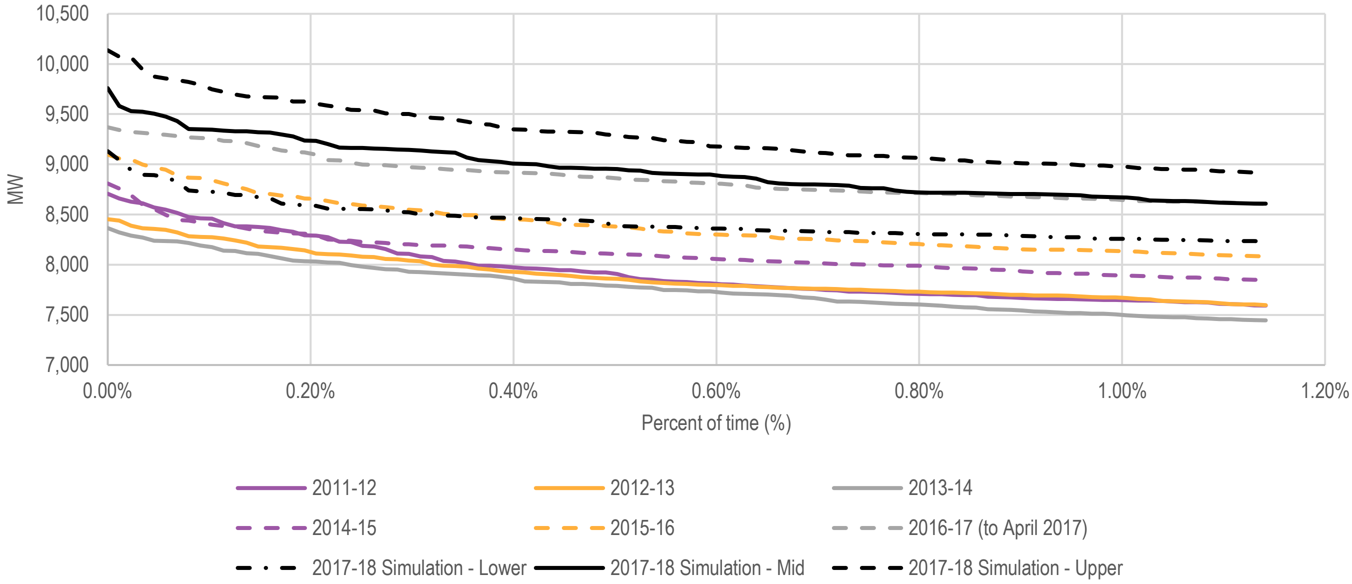
4.2.2 Estimating wholesale spot prices

ACIL Allen's proprietary electricity model, *PowerMark* was run to estimate the hourly pool prices for 2017-18 for the 506 simulations (46 demand and 11 outage sets).

Figure 4.8 shows the range of the upper one percent segment of the demand duration curves for the 46 simulated Queensland demand sets resulting from the methodology, along with the historical demands since 2011-12. The simulated demand sets represent the upper, lower and middle of the range of demand duration curves across all 46 simulated sets. It can be seen that the demand duration curves of the simulated demand sets for 2017-18 have a variation similar to that observed over the past five 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[6]. This variation in demand contributes to the variation in modelled pool price outcomes as discussed further in this section.

[6] The simulated demand sets for 2017-18 are generally higher than the pre-2016-17 observed demand outcomes due to the step increase in demand due to the in-field compression associated with the LNG export projects in Gladstone.

FIGURE 4.8 TOP ONE PERCENT HOURLY DEMANDS – QUEENSLAND



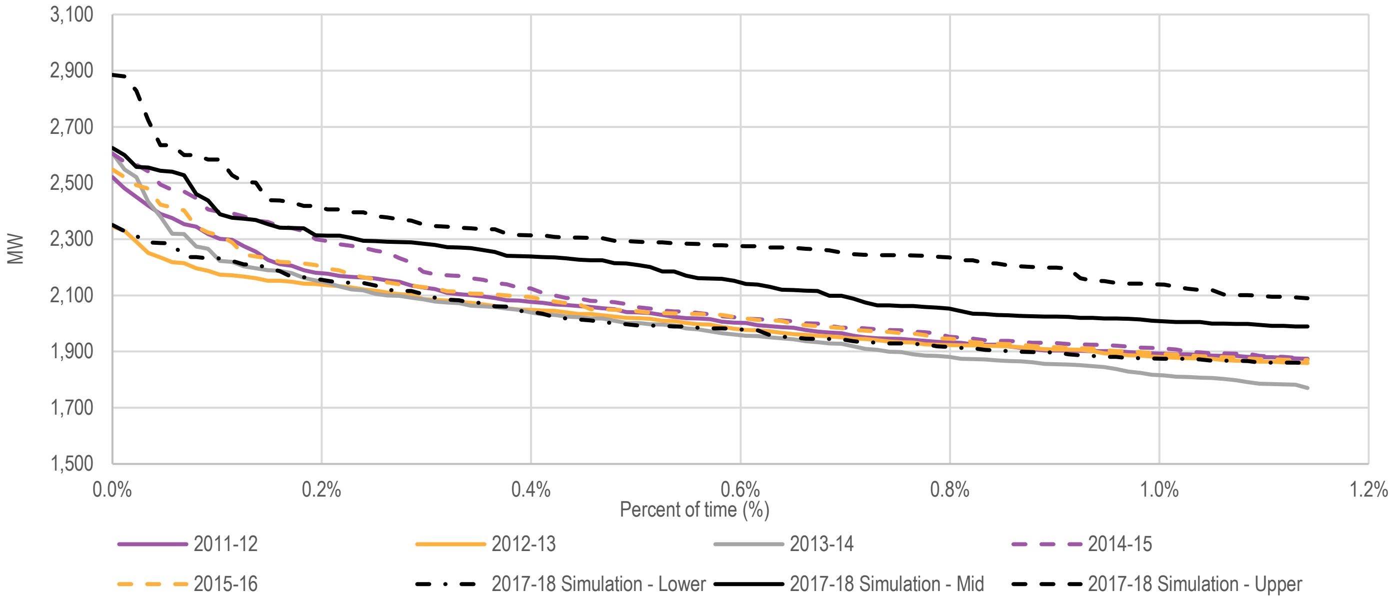
SOURCE: ACIL ALLEN ANALYSIS AND AEMO DATA

Figure 4.9 shows the range of the simulated Energex NSLP demand envelopes recent outcomes and covers an average range of about 600 MW across the top one percent of hours. This variation results in the annual load factor[7] of the 2017-18 simulated demand sets ranging between 27 percent and 34 percent compared with a range of 43 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.

[7] 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 4.9 TOP ONE PERCENT HOURLY DEMANDS – ENERGEX NSLP

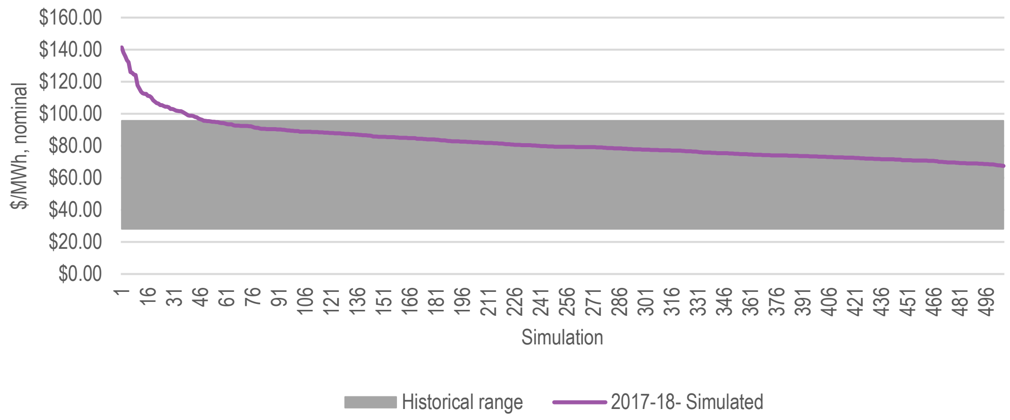


SOURCE: ACIL ALLEN ANALYSIS AND AEMO DATA

The modelled annual time weighted pool prices (TWP) for Queensland in 2017-18 from the 506 simulations range from a low of $67.47/MWh to a high of $141.39/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 $95.69/MWh to date in 2016-17.

Figure 4.10 compares the modelled Queensland TWP for the 506 simulations for 2017-18 with the Queensland TWPs from the past 16 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 2017-18 when compared with the past 16 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 2017-18 gas prices are projected to be around $11/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 506 simulations for 2017-18 cover an adequately wide range of possible annual pool price outcomes.

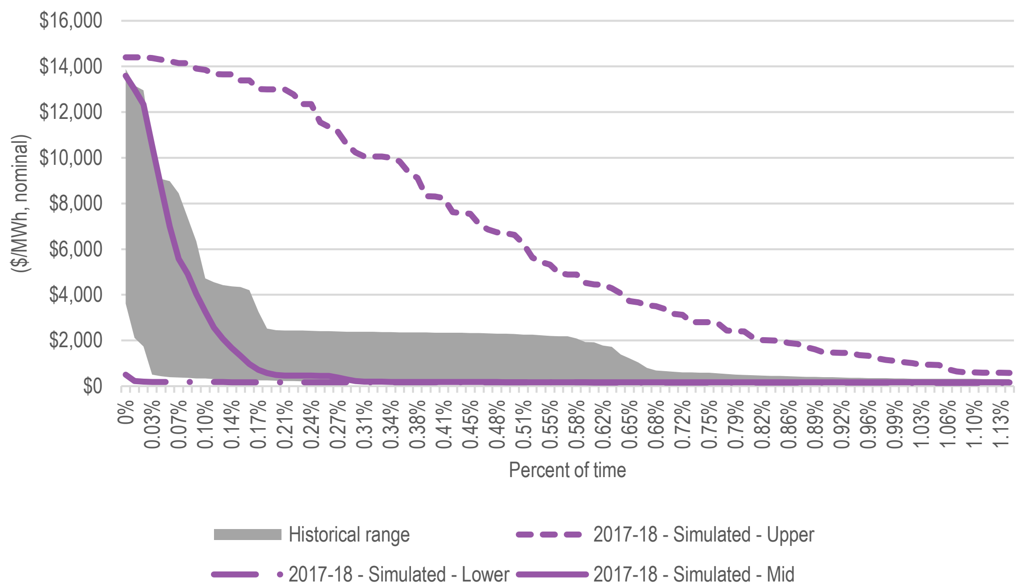
FIGURE 4.10 ANNUAL TWP FOR QUEENSLAND FOR 506 SIMULATIONS FOR 2017-18 COMPARED WITH ACTUAL ANNUAL OUTCOMES IN PAST YEARS



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 Figure 4.11. It is also notable, that as would be expected, the distribution of simulated price outcomes demonstrates a strong positive skewness.

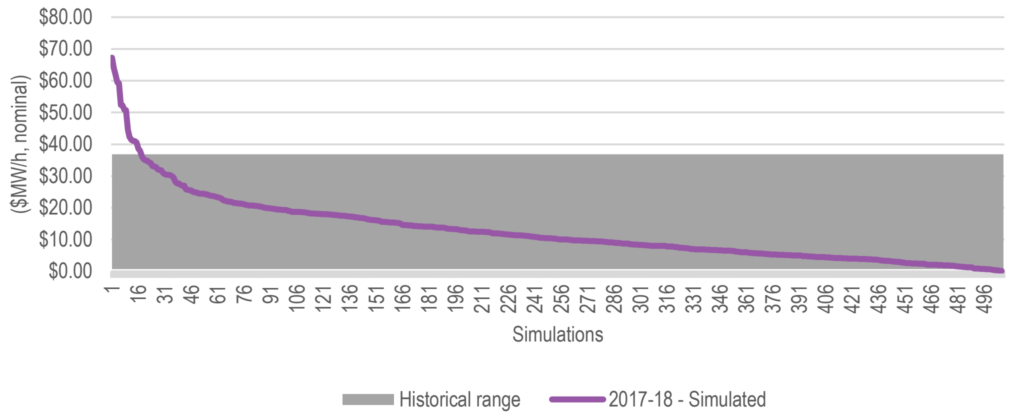
FIGURE 4.11 COMPARISON OF UPPER 1 PERCENT TAIL OF SIMULATED HOURLY PRICE DURATION CURVES FOR QUEENSLAND AND HISTORICAL OUTCOMES



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 506 simulations. The range in annual average contribution to the TWP, of hourly prices above $300/MWh, for the 506 simulations is consistent with those recorded in history as shown in Figure 4.12.

FIGURE 4.12 ANNUAL AVERAGE CONTRIBUTION TO THE QUEENSLAND TWP BY PRICES ABOVE $300/MWH FOR QUEENSLAND IN 2017-18 FOR 506 SIMULATIONS COMPARED WITH ACTUAL OUTCOMES IN PAST YEARS



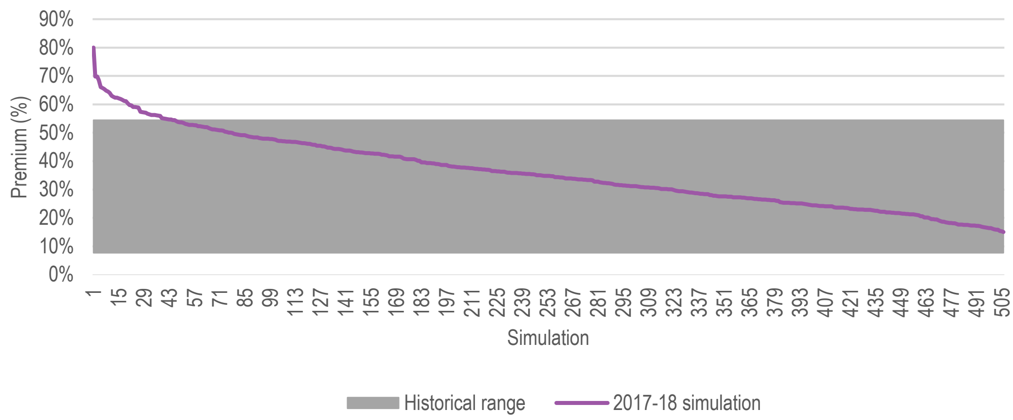
SOURCE: AEMO HISTORIC POOL PRICE DATA AND ACIL ALLEN RESULTS FROM POWERMARK MODELLING

Submissions to earlier 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 4.13 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 506 simulations for 2017-18, this percentage varies from 15 percent to 80 percent.

The comparison with actual outcomes over the past six years in Figure 4.13 demonstrates that the relationship between the Energex NSLP demand and Queensland pool prices in the 506 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 2017-18. It also provides a sound cross check on the shape of the NSLP demand and its relationship with the Queensland demand.

FIGURE 4.13 ANNUAL DWP FOR ENERGEX NSLP AS PERCENTAGE PREMIUM OF ANNUAL TWP FOR QUEENSLAND FOR 506 SIMULATIONS FOR 2017-18 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 506 simulations cover the range of expected price outcomes for 2017-18 in terms of annual averages and distributions. These comparisons clearly show that the 46 simulated demand traces combined with the 11 plant outage scenarios provide a sound basis for modelling the expected future spot market outcomes for 2017-18.

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 cap contracts. The prices for these hedging instruments are taken from the 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 46 demand sets for the quarter.

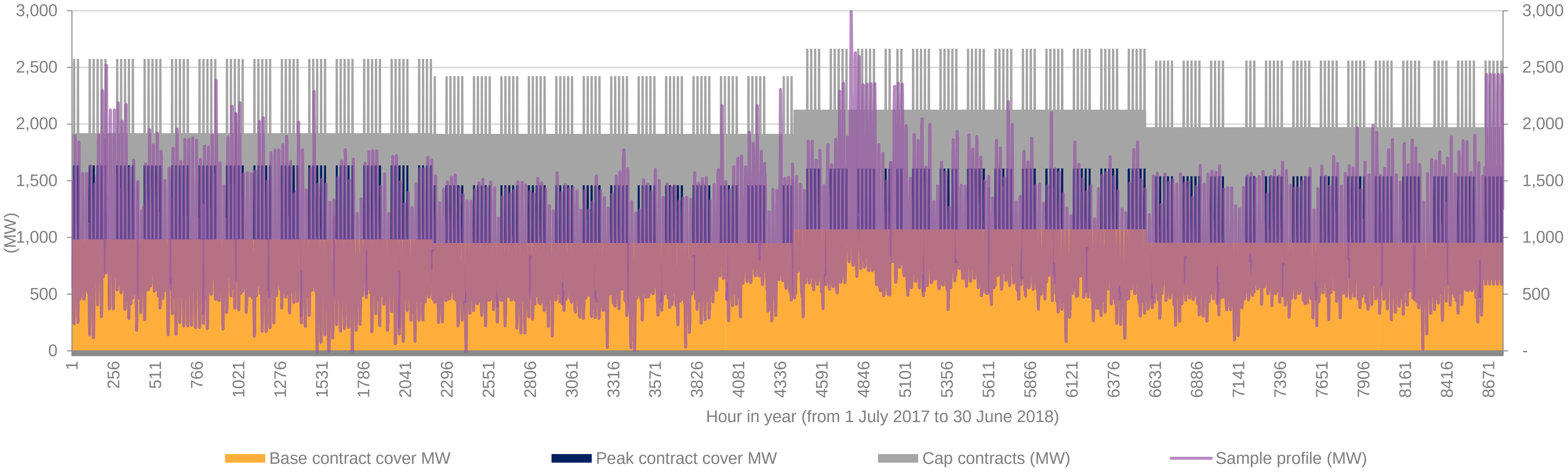
— The peak period contract volume is set to equal the 90th percentile of the peak period hourly demands across all 46 demand sets minus the base contract volumes for the quarter.

— The cap contract volume is set at 105 per cent of the median of the annual peak demands across the 46 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 46 demand sets for a given settlement class, and hence to each of the 506 simulations. To be clear, we are not altering the hedge volume (in MW terms) on an ex-post basis for each of the 46 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 506 simulations when calculating the wholesale energy cost. The contract volumes used are shown in Figure 4.14.

FIGURE 4.14 CONTRACT VOLUMES USED IN HEDGE MODELLING OF 506 SIMULATIONS FOR 2017-18 FOR ENERGEX NSLP

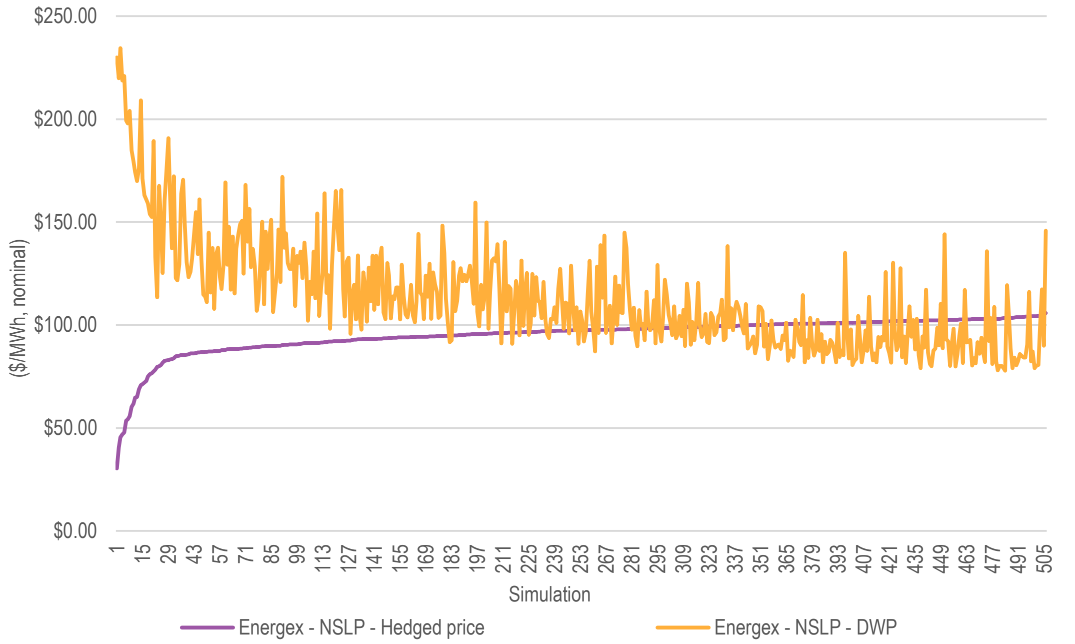


SOURCE: ACIL ALLEN

As hedge benefits are inversely related to pool prices, simulations with higher demand-weighted pool prices usually produce lower hedged prices. Figure 4.15 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 4.15 ANNUAL HEDGED PRICE AND DWP ($/MWH, NOMINAL) FOR ENERGEX NSLP FOR THE 506 SIMULATIONS – 2017-18



SOURCE: ACIL ALLEN MODELLING

4.2.4 Summary of estimated Wholesale Energy Cost

After applying the hedge model, the WEC is taken as the 95th percentile of the distribution containing 506 annual hedged prices. ACIL Allen's estimate of the WEC for each tariff class for the 2017-18 Final Determination are shown in Table 4.2.

TABLE 4.2 ESTIMATED WEC ($/MWH, NOMINAL) FOR 2017-18 AT THE QUEENSLAND REFERENCE NODE

Settlement class	2017-18 – Final Determination	2017-18 – Draft Determination	2016-17 – Final Determination	Change from 2016-17 to 2017-18 (%)
Energex - NSLP - residential and small business	$103.11	$86.40	$75.32	36.9%
Energex - Control tariff 9000 (31)	$56.76	$45.94	$42.31	34.2%
Energex - Control tariff 9100 (33)	$75.38	$62.48	$56.15	34.2%
Energex - NSLP - unmetered supply	$103.11	$86.40	$75.32	36.9%
Ergon Energy - NSLP - SAC HV, CAC and ICC	$92.75	$76.92	$65.69	41.2%
Ergon Energy - NSLP - SAC demand and street lighting	$92.75	$76.92	$65.69	41.2%

SOURCE: ACIL ALLEN ANALYSIS

Overall, the changes in estimated WEC from 2016-17 to 2017-18 are much larger compared with changes in determinations from previous years. The estimated WEC for the NSLPs has increased by about $27-28/MWh, and the control load tariffs have increased by about $14-19/MWh. The increase in estimated WEC reflects the projected continued tightening of the demand-supply conditions in the Queensland region as well as other regions of the NEM in 2017-18 due to the increase in demand from in-field gas compression associated with the LNG export facilities, little additional renewable capacity in Queensland, and the removal of Hazelwood power station coupled with the continued operation of Portland in Victoria. The projected increase in estimated WEC outcomes is consistent with the market modelling simulations and contract prices traded on the futures market.

As discussed earlier, 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 slightly less between 2016-17 and 2017-18 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[8]) 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[9] and TFS[10]
- Mandated LRET targets for 2017 and 2018 of 26,031 GWh and 28,637 GWh, respectively
- Published Renewable Power Percentage (RPP) for 2017 of 14.22 per cent
- Estimated RPP value for 2018 of 15.81 per cent[11]
- Binding Small-scale Technology Percentage (STP) for 2017 of 7.01 per cent
- Non-binding STP value for 2018 of 8.06 per cent[12]
- CER clearing house price for 2017 and 2018 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.

8 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.

9 AFMA data includes weekly prices up to and including 29 September 2016, after which the data ceased to be published

10 TFS data includes prices up to and including 3 April 2017.

11 2018 RPP value was estimated using liable electricity acquisitions implied in the non-binding STP value for 2018, as published by CER.

12 The non-binding 2018 STP estimate is based on the modelling prepared for CER for the 2017 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) up until September 2016 [13] and LGC forward prices provided by broker TFS from October 2016 to April 2017. In September 2016, AFMA ceased publishing LGC prices due to inadequate contributions by survey participants. TFS data has been used for the period after the AFMA data ceased. We have examined LGC forward prices provided by TFS prior to September 2016 are satisfied that they are consistent with the AFMA prices, and hence we think it reasonable to use the TFS data to supplement the analysis.

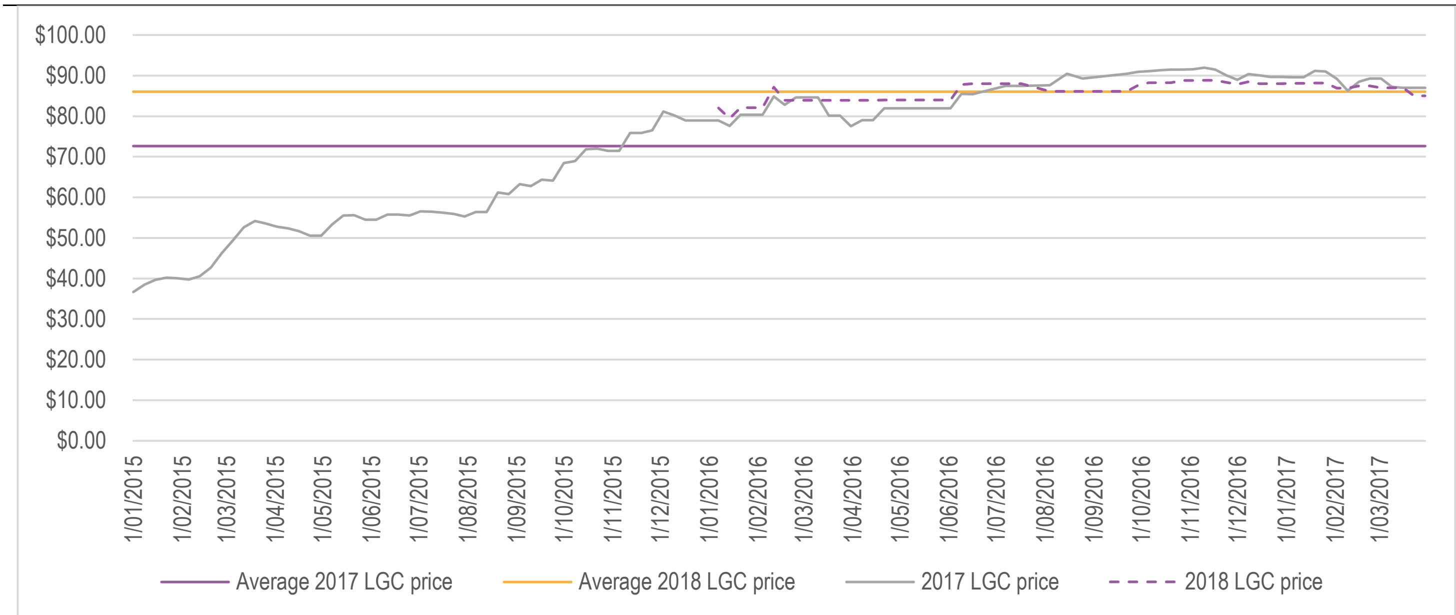
The LGC price used in assessing the cost of the scheme for 2017-18 is found by averaging the forward prices for the 2017 and 2018 calendar years, during the two years prior to the commencement of 2017 and 2018. This assumes that LGC coverage is built up over a two year period (see Figure 4.16). The average LGC prices calculated from the AFMA and TFS data are $72.66/MWh for 2017 and $86.04/MWh for 2018**.** Since the Draft Determination, LGC forward prices have softened slightly due to:

— A number of renewable projects reaching financial close in recent months with most of these projects expected to be commissioned during 2018. Although, the majority of these projects are outside of Queensland.

— The mix of near-term renewable projects skewed more towards solar than wind, with solar having a shorter lead time to commissioning.

— Liable entities announcing their intention to utilise the “make good’ provision under the LRET scheme, whereby if a liable entity has not complied in a given year, and rather than pay the penalty, they can provide a valid LGC in the future (up to three years) and surrender this in return for the $65 penalty.

FIGURE 4.16 LGC PRICES FOR 2017 AND 2018 ($/LGC, NOMINAL)



SOURCE: AFMA AND ACIL ALLEN ANALYSIS

The 2018 RPP value of 15.81 per cent was estimated using the mandated target 2018 and the total estimated electricity consumption implied in the non-binding STP value 2018.

The 2017 RPP value of 14.22 per cent has been set by the CER and does not need to be estimated.

Key elements of the 2018 RPP estimation are shown in Table 4.3.

13 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 2018 RPP VALUE

	2018
Non-binding STP (CER)	8.06%
Projected STCs (CER)	14,600,000
Implied total estimated electricity consumption	181,141,439
LRET target	28,637,000
Estimated RPP using implied total estimated electricity consumption	15.81%

[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 2017 and 2018 by multiplying the RPP values for 2017 and 2018 by the average LGC prices for 2017 and 2018, respectively. The cost of complying with the LRET in 2017-18 was found by averaging the calendar estimates.

Therefore, ACIL Allen estimates the cost of complying with the LRET scheme to be $11.97/MWh in 2017-18 as shown in Table 4.4.

TABLE 4.4 ESTIMATED COST OF LRET – 2017-18

	2017	2018	Cost of LRET 2017-18
RPP %	14.22%	15.81%	
Average LGC price ($/LGC, nominal)	$72.66	$86.04	
Cost of LRET ($/MWh, nominal)	$10.33	$13.60	$11.97

SOURCE: CER, AFMA, ACIL ALLEN ANALYSIS

4.3.2 SRES

The cost of the SRES for calendar years 2017 and 2018 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 2017-18.

The STPs published by CER are as follows:

- Binding 2017 STP of 7.01 per cent (equivalent to 12.4 million STCs as a proportion of total estimated electricity consumption for the 2017 year).
- Non-binding 2018 STP of 8.06 per cent (equivalent to 14.6 million STCs as a proportion of total estimated electricity consumption for the 2018 year).

ACIL Allen estimates the cost of complying with SRES to be $3.01/MWh in 2017-18 as set out in Table 4.5.

TABLE 4.5 ESTIMATED COST OF SRES – 2017-18

	2017	2018	Cost of SRES 2017-18
STP %	7.01%	8.06%	
STC clearing house price ($/STC, nominal)	$40.00	$40.00	
Cost of SRES ($/MWh, nominal)	$2.80	$3.22	$3.01

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 Final Determination from 2016-17.

Since the 2016-17 Final Determination, total renewable energy costs have increased by about 26 percent, driven by higher LGC prices.

TABLE 4.6 TOTAL RENEWABLE ENERGY POLICY COSTS ($/MWH) – FINAL DETERMINATION 2017-18, DRAFT DETERMINATION 2017-18 AND FINAL DETERMINATION 2016-17

	Final Determination 2017-18	Draft Determination 2017-18	Final Determination 2016-17
LRET	$11.97	$11.74	$7.83
SRES	$3.01	$3.47	$3.74
Total	$14.98	$15.21	$11.57

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)[14].

NEM fees are higher in 2017-18 due to the Power of Choice program (FRC segment) and upgrades to administrative processes and IT infrastructure (NEM fees segment).

Based on projected fees in AEMO's *Draft Budget & Fees 2017-18*, the total fee for 2017-18 is $0.53/MWh. The breakdown of total fees is shown in Table 4.7.

TABLE 4.7 NEM MANAGEMENT FEE ($/MWH) – 2017-18

Cost category	Fees ($/MWh)
NEM fees (admin, registration, etc.)	$0.41
FRC - electricity	$0.075
NTP - electricity	$0.021
ECA - electricity	$0.027
Total NEM management fees	$0.53

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

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

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 2017-18, the cost of ancillary services is estimated to be $0.34/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 $12,553.

TABLE 4.8 AEMO PRUDENTIAL COSTS – 2017-18

Factor	Summer	Winter	Shoulder
Load Weighted Expected Price	$140.53	$98.07	$95.67
Participant Risk Adjustment Factor	1.2816	1.2064	1.1689
OS Volatility factor	1.69	1.31	1.44
PM Volatility factor	2.66	1.71	1.84
Loss Factor	1.065	1.065	1.065
OSL	$15,994	$7,666	$7,719
PML	$3,199	$1,533	$1,544
MCL	$19,192	$9,199	$9,263
Average MCL		**$12,553**	

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 $12,553/42 = $298.41/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 $298.41 gives $0.858/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 1.5 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 percent on average for a base contract, 10 percent for a peak contract and 19 percent for a cap contract
— the intra monthly spread charge currently set at $9,900 for a base contract of 1 MW for a quarter, $9,600 for a peak contract and $6,100 for a cap contract
— the spot isolation rate currently set at $700 for a base contract, $400 for a cap contract and $1,900 for a peak contract.

In previous years ACIL Allen used baseload contracts as proxies for hedge prudential costs. We have refined the methodology this year to take into account the relative proportion of each type of contract used in the hedge model and any over-contracting modelled in the hedge model.

Using the annual average futures price and applying the above factors gives an average initial margin for each quarter (rounded up) as shown in Table 4.9 below. This is divided by the average hours in a quarter. Then applying the assumed funding cost of 7.71[15] percent but adjusted for an assumed 1.5 percent return on cash lodged with the clearing (giving a net funding cost of 6.21 percent) results in the prudential cost per MWh for each contract type as shown in the table.

TABLE 4.9 HEDGE PRUDENTIAL FUNDING COSTS BY CONTRACT TYPE

Contract Type	Average contract price	Initial margin (rounded up to nearest $1000)	Prudential cost per MWh
Base	$70.33	$23,000.00	$0.65
Peak	$100.26	$21,000.00	$1.39
Cap	$13.57	$13,000.00	$0.37

SOURCE: ACIL ALLEN ANALYSIS

However, the hedge model used is designed to conservatively cover all load at the extremes and so results in an over-contracted position against the average load. The volume of hedges (MWh) in each category have been calculated as a proportion of the average annual load in the Energex NSLP to give a proportional factor. The product of the prudential cost per MWh for each contract type and the proportion of each contract in the hedge model profile provides the total hedge prudential cost per MWh associated with each contract type. These are then summed to establish the total hedge prudential costs as shown in Table 4.10.

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

TABLE 4.10 HEDGE PRUDENTIAL FUNDING COSTS FOR ENERGEX NSLP

Contract Type	Prudential cost per MWh	Proportion of contract hedged against average annual energy	Prudential cost per MWh
Base	$0.65	1.2190	$0.80
Peak	$1.39	0.3060	$0.42
Cap	$0.37	1.2238	$0.45
Total cost			**$1.67**

SOURCE: ACIL ALLEN

Total prudential costs

Adding the AEMO and hedge prudential costs gives a total prudential requirement as set out in Table 4.11.

TABLE 4.11 TOTAL PRUDENTIAL COSTS ($/MWH) - 2017-18

Cost category	Cost
AEMO pool	$0.86
Hedge	$1.67
Total	$2.53

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 4.12 for the 2017-18 Final Determination and is compared to the costs from the Final Determination for 2016-17.

TABLE 4.12 TOTAL OF OTHER COSTS ($/MWH) – FINAL DETERMINATION 2017-18, DRAFT DETERMINATION 2017-18 AND FINAL DETERMINATION 2016-17

Cost category	Final Determination 2017-18	Draft Determination 2017-18	Final Determination 2016-17
NEM management fees	$0.53	$0.51	$0.48
Ancillary services	$0.34	$0.29	$0.33
Hedge and pool prudential costs	$2.53	$2.28	$0.99
Total	$3.40	$3.08	$1.80

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 (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 marginal loss factors (MLFs) for the Energex and Ergon Energy east zone Transmission Node Identities (TNIs). This analysis results in a transmission loss factor of 1.008 for Energex and 0.985 for the Ergon Energy east zone. These estimates are based on AEMO's MLFs for 2017-18 weighted by the 2014-15 energy for the TNIs [16].

The distribution loss factor by settlement class for the Energex area and the Ergon energy east zone are taken from AEMO's Distribution Loss Factors for 2017-18.

The estimation of transmission and distribution loss factors for the settlement classes to be used in calculating energy costs for the Final Determination for 2017-18 shown in Table 4.13.

There has been a general reduction in losses at connection points in Central and Northern Queensland due to an increase in power flow from Central Queensland toward the RRN because of 3.3% lower regional demand forecast (LNG loads) and an increase in exports due to closure of Hazelwood in Victoria.

TABLE 4.13 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	1.056	1.008	1.065
Energex - Control tariff 9000	1.056	1.008	1.065
Energex - Control tariff 9100	1.056	1.008	1.065
Ergon Energy - NSLP - SAC HV, CAC and ICC	1.030	0.985	1.014
Ergon Energy - NSLP - SAC demand and street lighting	1.096	0.985	1.079

DATA SOURCE: ACIL ALLEN ANALYSIS BASED ON QUEENSLAND TNI ENERGY FOR 2014-15, MLFS FOR 2017-18AND ENERGEX AND ERGON ENERGY EAST ZONE DLFS FOR 2017-18 FROM AEMO.

For the Final Determination for 2017-18 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[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:

*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 2017-18 total energy costs (TEC) for the Final Determination for each of the settlement classes are presented in Table 4.14.

[16] Updated energy data for the TNIs will not be available for the calculation of loss factors for the 2017-18 Determination, due to a restriction by AEMO on the provision of this data.

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

TABLE 4.14 ESTIMATED TEC FOR 2017-18 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 ($/MWh)	Change from 2016-17 Final Determination ($/MWh)	Change from 2016-17 Final Determination (%)
Energex - NSLP - residential and small business	$103.11	$14.98	$3.40	1.065	$7.90	$129.39	$34.94	36.99%
Energex - Control tariff 9000 (31)	$56.76	$14.98	$3.40	1.065	$4.88	$80.02	$20.72	34.94%
Energex - Control tariff 9100 (33)	$75.38	$14.98	$3.40	1.065	$6.09	$99.85	$25.81	34.86%
Energex - NSLP - unmetered supply	$103.11	$14.98	$3.40	1.065	$7.90	$129.39	$34.94	36.99%
Ergon Energy - NSLP - SAC HV, CAC and ICC	$92.75	$14.98	$3.40	1.014	$1.56	$112.69	$29.52	35.49%
Ergon Energy - NSLP - SAC demand and street lighting	$92.75	$14.98	$3.40	1.079	$8.78	$119.91	$31.36	35.42%

SOURCE: ACIL ALLEN ANALYSIS

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