ACIL ALLEN CONSULTING

REPORT TO
AUSTRALIAN ENERGY REGULATOR
10 SEPTEMBER 2019

DEFAULT MARKET OFFER

ESTIMATING WHOLESALE ENERGY AND ENVIRONMENTAL COSTS

PHASE 1: INITIAL SCOPING AND ASSESSMENT OF FORECASTING OPTIONS

ACIL ALLEN CONSULTING PTY LTD
ABN 68 102 652 148

LEVEL NINE
60 COLLINS STREET
MELBOURNE VIC 3000
AUSTRALIA
T+61 3 8650 6000
F+61 3 9654 6363

LEVEL NINE
50 PITT STREET
SYDNEY NSW 2000
AUSTRALIA
T+61 2 8272 5100
F+61 2 9247 2455

LEVEL FIFTEEN
127 CREEK STREET
BRISBANE QLD 4000
AUSTRALIA
T+61 7 3009 8700
F+61 7 3009 8799

LEVEL SIX
54 MARCUS CLARKE STREET
CANBERRA ACT 2601
AUSTRALIA
T+61 2 6103 8200
F+61 2 6103 8233

LEVEL TWELVE, BGC CENTRE
28 THE ESPLANADE
PERTH WA 6000
AUSTRALIA
T+61 8 9449 9600
F+61 8 9322 3955

167 FLINDERS STREET
ADELAIDE SA 5000
AUSTRALIA
T +61 8 8122 4965

ACILALLEN.COM.AU

SUGGESTED CITATION FOR THIS REPORT

DEFAULT MARKET OFFER: ESTIMATING WHOLESALE ENERGY AND ENVIRONMENTAL COSTS FOR 202021: PHASE 1, ACIL ALLEN, SEPTEMBER 2019

CONTENTS

CONTENTS

TABLES

1 INTRODUCTION

ACIL Allen Consulting (ACIL Allen) has been engaged by the Australian Energy Regulator (AER) to support the AER in estimating specific cost inputs required for the determination of Default Market Offer (DMO) prices. Specifically, ACIL Allen is required to provide consultancy services to the AER to estimate the underlying wholesale and environmental cost inputs to inform the determination for 2020-21.

These estimates are to be based on the relevant cost drivers for an efficient retailer supplying electricity to residential and small business customers in non-price regulated jurisdictions (excluding Victoria).

ACIL Allen's work is broadly divided into two phases:

- **Phase 1**: Initial scoping and assessment of forecasting options
  - The services in this phase include identifying, scoping and developing a methodology to estimate underlying wholesale and environmental cost inputs to forecast changes in retail electricity costs. The deliverables in this phase will form part of the position paper for the DMO (Position Paper) to be published by the AER.
- **Phase 2**: Estimating the underlying costs to inform the DMO 2020-21 determination
  - If required, the services in this phase include estimating the underlying cost inputs for the DMO determination based on the methodology developed in Phase 1. The deliverables in this phase will form part of draft DMO prices (Draft Determination) and the final DMO prices (Final Determination).

This report summarises our Phase 1 analysis and findings, and is set out as follows:

- We identify the components of the wholesale and environmental costs in chapter **2**.
- In Chapter **3** we identify and describe the various approaches used in past regulatory determinations to estimate wholesale and environmental costs.
- Chapter **4** summarises the evaluation principles we use to assess the various estimation approaches.
- Chapter **5** provides our assessment of the different estimation approaches against the evaluation principles, and the proposed approach.
- Chapter **6** sets out the details of the proposed approach.

More details of the scope of work for Phase 1

The wholesale and environmental cost estimation methodology applies to the following distribution zones:

- New South Wales: Ausgrid, Endeavour, Essential
- Queensland: Energex
- South Australia: SA Power Networks (SAPN).

The cost estimates for each of the above distribution zones are to be provided to enable the AER to calculate the forecast changes in retail electricity bill costs for the following customer types:

1. Residential without controlled load
2. Residential with controlled load
3. Flat rate small business customers.

Our report is to transparently set out the forecasting methodology to enable stakeholders to make an informed assessment as to how the forecasts are, or are proposed to be, derived. The report is to discuss all relevant inputs, such as load profiles, and material information to assist stakeholders in assessing the consultant methodology.

This has been achieved by:

— identifying and scoping sub-components of wholesale and environmental costs, informed by local and international research
— identifying and evaluating different options to estimate wholesale and environmental costs
— identifying assumptions and evaluating data requirements (including potential sources of the data).

2 COMPONENTS OF WHOLESALE AND ENVIRONMENTAL COSTS

Although the AER's brief to ACIL Allen refers to *wholesale energy and environmental costs*, it is important to consider all components of a retailer's energy purchase costs.

Broadly, the energy purchase costs comprise the following four components:

— wholesale energy costs (WEC)

— costs of complying with state and national government environmental policies, including the Renewable Energy Target (RET)

— other costs, such as 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.

As the energy purchase costs are broader than the wholesale energy and environment costs, we have referred to them as wholesale and environment costs in this report.

We identify and define each of the components of the wholesale and environment costs in the following sections.

2.1 Wholesale energy costs

Generators in the NEM sell their output to the wholesale spot market and all customers (including retailers acting on behalf of consumers) purchase their electricity requirements from the wholesale spot market. For a given half-hour and region of the NEM, a retailer will pay the Australian Energy Market Operator (AEMO) the regional reference price (RRP) (the spot price) multiplied by their load. This represents the WEC in its simplest form but does not take into account the way retailers manage load and spot price volatility risk.

Retailers operating in the NEM must purchase their energy requirements from the electricity spot market. Since spot prices exhibit significant volatility and retailers are generally required to supply customers at fixed prices for a given period of time, retailers face significant price risk. At times, the level of volatility could mean significantly more cash flow is required to fund spot purchases than is received under electricity supply contracts to customers on fixed prices.

While this risk could be managed by larger amounts of working capital, holding large working capital reserves that may be used relatively infrequently is expensive. In practice, a better alternative is to hedge the price risk through taking on physical exposure to the electricity pool or by entering into derivative agreements indexed against the electricity spot price. As it happens, generators have the opposite price risk profile to retailers as they face pool price exposure on revenues. In general, this allows retailers to enter into a wide range of physical and derivative arrangements to manage price risk.

These arrangements typically include:

- acquiring and using own generation (vertical integration)
- power purchase agreements (PPAs) or tolling agreements with third party generators
- bilateral arrangements between retailers and generators
- broker arranged over the counter (OTC) contracts (may include a wide range of contract forms)
- exchange traded swap and cap contracts available in the futures market.

2.2 Environmental costs

Environmental costs can be grouped into national and state-based schemes and represent the costs of a retailer complying with state and federal government policies, including the Renewable Energy Target (RET), as well as state-based energy efficiency schemes.

It is important to note that when referring to environmental costs we are considering the direct costs of these schemes only, and not their indirect influence on other costs. For example, schemes that incentivise development of renewable capacity may well have an impact on wholesale electricity prices, and hence the WEC, but this impact is accounted for separately when considering the WEC.

2.2.1 National schemes

Environmental costs associated with national schemes are limited to the cost of complying with the Large-scale Renewable Energy Target (LRET) and the Small-scale Renewable Energy Scheme (SRES).

These schemes provide incentives for the electricity sector to increase generation from renewable sources and reduce greenhouse gas emissions. The costs of these incentives are paid by retailers through the purchase of large-scale generation certificates (LGCs) and small-scale technology certificates (STCs). Retailers surrender the purchased LGCs and STCs to the Clean Energy Regulator (CER) to meet their obligations under the schemes.

2.2.2 State-based schemes

Given our brief is limited to Queensland, New South Wales and South Australia, we identify the relevant cost components for these regions only. We also identify which of these schemes are accounted for in, or recovered by, network tariffs, and hence can be excluded from the environmental cost component to avoid double counting.

Queensland

The only state-based environmental scheme applicable in Queensland is the Solar Bonus Scheme. There are currently no certificate-based energy efficiency schemes that need to be accounted for in Queensland. The Queensland Government's current Affordable Energy Plan includes rebates for the installation of energy efficient appliances, and interest free loans for Queensland households to install rooftop solar PV and storage systems, but these are funded directly by the Government and hence do not need to be considered in assessing the DMO price.

Solar Bonus Scheme

The Solar Bonus Scheme applied to rooftop PV installations which were registered before July 2012. Prior to July 2017, the cost of the scheme was recovered by Ergon and Energex through their respective network tariffs. However, the cost of the scheme is now funded by the Government and therefore does not need to be accounted for in the DMO.

The QCA notes in its 2019-20 Final Determination report[1], that:

The costs associated with the Solar Bonus Scheme have been fully funded from the Queensland Government budget from 2017–18 onwards. Since then, these costs no longer form a component of

[1] http://www.qca.org.au/getattachment/8de1a2d9-4484-4fd5-8d39-c61102d627bb/Final-Determination-2019-20-Notified-prices.aspx, p. 52.

customer bills. The Solar Bonus Scheme is now a legacy scheme and cannot be accessed by new customers.

New South Wales

There are currently two state-based schemes that are relevant in New South Wales:

— the Energy Savings Scheme (ESS)

— the Climate Change Fund (CCF).

These are the two schemes also identified by the AEMC in its 2018 Residential Electricity Price Trends Review report[2].

There are other schemes in New South Wales, such as Solar for Low Income Households which allows eligible households to forgo their energy rebate and receive an installed rooftop solar PV system. These schemes are funded directly by the New South Wales Government and do not need to be accounted for in this analysis.

Energy Saving Scheme

The ESS places an obligation on electricity retailers in New South Wales to obtain and surrender Energy Savings Certificates (ESC), which represent energy savings resulting from consumers installing energy efficient appliances. The scheme commenced in 2009, and in its review in 2014-15, the New South Wales Government extended the life of the scheme to 2025.

The retailers' liabilities under the scheme are set as a fixed percentage of electricity sales for which ESCs need to be surrendered in each calendar year. The cost of this scheme is not funded directly by government, nor is it recovered via network tariffs; therefore, it needs to be accounted for as a component of the environmental costs category for New South Wales consumers.

Climate Change Fund

The Climate Change Fund (CCF) was set up by the New South Wales Government in 2007 to encourage energy and water saving activities. The legislation requires New South Wales network businesses to contribute to the CCF, which is collected from customers via network tariffs. Therefore, this cost is already accounted for within network tariffs and hence is not considered further in this report.

South Australia

There are currently two state-based schemes that are relevant in South Australia:

— the Retailer Energy Efficiency Scheme (REES)

— the solar feed-in tariff schemes (FiT).

Retailer Energy Efficiency Scheme

The REES incentivises households and small businesses in South Australia to reduce energy consumption by requiring retailers to offer energy audits, as well as setting energy efficiency targets. The targets are set by the Essential Services Commission of South Australia (ESCOSA). REES commenced in 2009 and according to ESCOSA's June 2019 REES information sheet is set to operate until 31 December 2020.[3]

The cost of the REES is recovered directly through retail electricity tariffs, and therefore should be considered as part of the environment cost component – but care needs to be taken that these costs are not double counted in the retail cost component.

Solar Feed-in Tariffs

In 2008, the South Australian Government introduced what was known as the distributor feed-in tariff or the solar feed-in scheme, which is only available for eligible solar PV systems that were connected

[2] https://www.aemc.gov.au/sites/default/files/2018-12/2018%20Price%20Trends%20-%20Final%20Report%20-%20CLEAN.PDF, pp. 73-74.
[3] https://www.escosa.sa.gov.au/ArticleDocuments/214/20190627-REES-RegulatoryFrameworkInformationSheet.pdf.aspx?Embed=Y

to the grid before 30 September 2011. This scheme expires in 2028, but the costs are recovered via network tariffs and therefore does not need to be accounted for in this analysis.

In addition to the distributor FiT, the Government also introduced a retailer FiT, which set a minimum rate paid to PV exports. However, this scheme stopped in 2017 when ESCOSA ceased setting the minimum value for exports.

2.3 Other costs

We identify a set of other energy cost components incurred by a retailer when purchasing energy from the wholesale market, which are not included in the retailer operating costs and margins. These are:

- NEM fees
- ancillary services charges
- costs of the Reliability and Emergency Reserve Trader (RERT)
- costs of meeting prudential requirements.

NEM fees and ancillary services charges are also identified by the AEMC in its 2018 Residential Electricity Price Trends Review report[4] as part of the cost of purchasing wholesale electricity. However, the AEMC report does not explicitly include prudential costs (which we discuss separately below).

NEM fees

NEM 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).

Ancillary services charges

Ancillary services charges cover the costs of services used by AEMO to manage power system safety, security and reliability. AEMO recovers the costs of these services from market participants. These fees are published by AEMO on its website on a weekly basis.

Reliability and Emergency Reserve Trader (RERT)

The RERT is a mechanism under the National Electricity Rules (NER) that allows AEMO to contract for emergency reserves such as generation or demand response that are not otherwise available in the market to maintain power system reliability and system security.

AEMO is permitted to procure RERT contracts in order to ensure that reliability of supply meets the reliability standard in a given region of the NEM. Under the current reliability standard, expected unserved energy (USE) must not be more than 0.002 per cent of the total energy demanded in a given year.

To the extent that low reserve conditions are being forecast (i.e. a forecast breach of the reliability standard), AEMO can procure emergency reserves up to nine months prior to the expected shortfall. As from 26 March 2020, AEMO will be able to procure emergency reserves in advance of up to one year.

The RERT can be thought of as two elements in terms of cost:

1. When AEMO determines to enter into contracts for the provision of additional reserves
2. When AEMO determines to dispatch scheduled reserves under scheduled reserve contracts or activate unscheduled reserves under unscheduled reserve contracts.

AEMO is now required to publish quarterly reports on RERT costing.

Prior to 2017, contracts for reserve capacity were signed only three times – in 2005, 2006 and 2014. In each case, reserve capacity was purchased for both Victoria and South Australia but did not need to be dispatched. In 2005 a total of 84 MW of reserve capacity was contracted for the period 31

[4] https://www.aemc.gov.au/sites/default/files/2018-12/2018%20Price%20Trends%20-%20Final%20Report%20-%20CLEAN.PDF, p.27.

January to 4 March (33 days) at a cost of $1,000,000; in 2006, a total of 375 MW for the period 16 January to 10 March (54 days) at a cost of $4,400,000; and in 2014, 650 MW for the period 15-17 January (3 days). [5]

Since 2017, two publicly available reports for RERT costs have been published:

— AEMO reported in its RERT 2017-18 Cost Update report[6] that the RERT cost $51,990,000, split as follows:
  – Victoria $50,764,130.53
  – South Australia $1,229,415.36.
— AEMO reported the RERT in 2018-19[7] was secured on two occasions:
  – Thursday 24 January 2019
  – Friday 25 January 2019
  – At a total cost of $34,500,000
  – These costs were recovered as follows from Victorian and South Australian consumers:
    - Commercial and Industrial
    - Using typical commercial and industrial energy usage tariffs for the 2018 calendar year, the cost of RERT would equate to an annual average of approximately:
    - • $0.79 per MWh in Victoria
    - • $0.16 per MWh in South Australia
    - Residential Customers
    - Using standard energy rates, and typical residential customer usage tariffs over the 2018 calendar year, the total RERT costs on 24 and 25 January would equate to an average annual cost per residential customer of approximately:
    - • $3.20 in Victoria.
    - • $0.80 in South Australia.

Costs of meeting prudential requirements

Prudential costs are incurred by a retailer to provide financial guarantees to AEMO, and to lodge initial margins with the Australian Stock Exchange (ASX) to trade in futures contracts.

It is reasonable to consider that the costs of meeting prudential obligations to AEMO and to hedging providers are specific to the purchasing of energy and managing energy price risk, and that these should be accounted for separately.

It is possible that the AEMC in its price trends report implicitly includes prudential costs within the so-called residual component of the retail tariff, since the residual component is estimated based on the difference between the retailer price and the sum of the other components in the electricity cost stack. Therefore, the AER needs to take care not to double count this cost when determining the DMO.

2.4 Energy losses

Some electricity is lost when it is transported over transmission and distribution networks to customers. As a result, retailers must purchase additional electricity to allow for these losses when supplying customers.

The components of the wholesale and environmental costs are normally expressed at the relevant regional reference node. Therefore, prices expressed at the regional reference node must be adjusted for losses in the transmission and distribution of electricity to customers – otherwise the wholesale and environmental costs are understated. The cost of network losses associated with wholesale and environmental costs is separate to network costs and are not included in network tariffs.

[5] https://grattan.edu.au/wp-content/uploads/2017/05/889-Powering-through.pdf
[6] https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/RERT-Update---cost-of-RERT-2017-18.pdf
[7] https://www.aemo.com.au/-/media/Files/Electricity/NEM/Emergency_Management/RERT/RERT-report-for-2018-19.pdf

2.5 Summary of cost components to be considered

Table 2.1 visually summarises, for each given distribution zone, the cost components to be included when estimating the wholesale and environmental costs incurred by a retailer when procuring wholesale energy in the NEM.

TABLE 2.1 COMPONENTS TO BE INCLUDED IN THE WHOLESALE AND ENVIRONMENTAL COST ESTIMATES

	NSW: Ausgrid, Endeavour, Essential	Queensland: Energex	South Australia: SAPN
Wholesale energy cost (WEC)	● (green)	● (green)	● (green)
Environmental costs			
– Large-scale Renewable Energy Target (LRET)	● (green)	● (green)	● (green)
– Small-scale Renewable Energy Scheme (SRES)	● (green)	● (green)	● (green)
– Queensland Solar Bonus Scheme	● (red)	● (red)	● (red)
– New South Wales Energy Savings Scheme (ESS)	● (green)	● (red)	● (red)
– New South Wales Climate Change Fund (CCF)	● (red)	● (red)	● (red)
– South Australia Retailer Energy Efficiency Scheme (REES)	● (red)	● (red)	● (green)
– South Australia solar feed-in tariff schemes (FiT)	● (red)	● (red)	● (red)
Other costs			
– Market fees	● (green)	● (green)	● (green)
– Ancillary service costs	● (green)	● (green)	● (green)
– Reliability and Emergency Reserve Trader (RERT)	● (green)	● (green)	● (green)
– Prudential costs	● (green)	● (green)	● (green)
– Energy losses	● (green)	● (green)	● (green)

Note: ● (green) = included; ● (red) = excluded.

SOURCE: ACIL ALLEN

3 IDENTIFY OPTIONS FOR ESTIMATING COST COMPONENTS

In this chapter we identify and briefly describe the different approaches available to estimate each of the cost components. For most components there is only one approach.

Most of our attention focusses on the WEC and LRET costs as there are several approaches available to estimate these.

This chapter does not evaluate the different approaches (this is done in chapter **5**), after the evaluation principles are identified (in chapter **4**).

3.1 Wholesale energy costs

There are two broad approaches to estimating the WEC:

— a theoretical long run marginal cost (LRMC) approach

— a market-based approach.

The long-term average of annual WEC estimates from both approaches in theory should converge.

3.1.1 The LRMC approach

The LRMC approach estimates the levelised capital, operating and maintenance (O&M) and fuel costs of supplying an additional unit of energy. There are a number of variations of the LRMC approach, including:

— *greenfield* approach, which builds a least cost portfolio of generators from scratch

— *brownfield,* which accounts for the current mix of generation capacity.

At a high level, the approach estimates the least cost combination of new generation investment required to satisfy demand.

The approach necessarily takes a long-term view on generation investment requirements and input costs, essentially estimating the efficient investment (and associated costs) required to satisfy demand over a projection period of 25 years or so, from which the estimated cost of supply for year one of the projection period (the determination year) is extracted.

In a competitive market, the price outcomes will align with the LRMC over the long-term. If the price outcomes were lower than the LRMC over the long term, generators would not be viable. If the market is competitive then the price outcomes will not be higher than the LRMC values over the long term.

As the price outcomes align with the LRMC over the long term, the LRMC has been used in the past by some regulators in determining the energy cost component of the retail electricity price.

However, it has not been used for about eight years in Queensland, nine years in South Australia prior to deregulation in 2013; and New South Wales used a combination of the market-based and LRMC approach prior to deregulation in 2014. A market-based approach has been used in the ACT since 2010, and an indexing approach prior to 2010.

There have been numerous reviews discounting the use of the LRMC approach, for example:

— ICRC in 2010: *Final Technical Paper: Model for Determining the Energy Purchase Cost Component of the Transitional Franchise Tariff: Report 3 of 2010*
— ACIL Allen in 2012 for the QCA: *Draft methodology for estimating the energy purchase costs for each retail electricity tariff for Queensland in 2012/13*[8]
— ACIL Allen in 2012 for ESCOSA: *Wholesale electricity cost investigation Approaches to setting the wholesale electricity cost allowance July 2012*[9]

The key reason given for not using the LRMC approach is that it does not estimate the costs that would be incurred by an efficient and prudent retailer in purchasing energy in a given year. Rather, it provides an indication of the cost of generation in the long term. In the short term, the costs incurred by retailers in purchasing energy are expected to be higher or lower than the LRMC depending on market conditions. ACIL Allen notes that based on experience in its engagements with the QCA, retailers tend to be supportive of the LRMC approach when it is likely to result in a higher cost estimate than the market-based approach, and silent when it results in a lower estimate.

For this reason and given that regulators have not used the LRMC approach for several years, the LRMC approach is not considered further in this report.

3.1.2 Market-based approach

A market-based approach involves estimating the wholesale energy purchase costs that a prudent and efficient electricity retailer would be expected to incur in a given determination year.

Energy purchase costs are incurred by a retailer when purchasing energy from the NEM spot market to satisfy their retail load. However, given the volatile nature of wholesale electricity spot prices, which is an important and fundamental feature of an energy-only market (i.e. a market without a separate capacity mechanism), and that retailers charge their customers based on fixed rate tariffs (for a given period), a prudent retailer is incentivised to hedge its exposure to the spot market.

Hedging can be achieved by a number of means – a retailer can own or underwrite a portfolio of generators (the gen-tailer model), enter into bilateral contracts directly with generators, purchase over the counter (OTC) contracts via a broker, or take positions on the futures market. Typically, a retailer will employ a number of these hedging approaches. In addition, a retailer may choose to leave a portion of their load exposed to the spot market.

Use of financial derivatives in estimating the WEC

As discussed above, retailers purchase electricity in the NEM at the spot price and use a number of strategies to manage their risk. Market-based approaches adopted by regulators for estimating the WEC make use of financial derivative data given that it is readily available and transparent. This is not to say regulators are of the view that retailers only use financial derivatives to manage risk – it simply reflects the availability and transparency of data.

Some retailers also use vertical integration and Power Purchase Agreements (PPAs) to manage their risk. However, the associated costs, terms and conditions of these approaches are not readily available in the public domain. Further, smaller retailers may not be in a position to use vertical integration or PPAs and hence rely solely on financial derivatives.

Additionally, the value of long-dated assets associated with vertical integration and PPAs is determined by conditions in the market at a given point in time. The price in a PPA or the annualised historical cost of generation reflects the value of the generation anticipated at the time of commitment when the investor was faced with a variety of uncertain futures. Once an investment is committed, the costs are sunk. As time proceeds, the value of the generation asset is determined by the actual future that eventuates and may be quite different to the value expected at the time of commitment. As a

[8] http://www.qca.org.au/getattachment/d2aeec19-eae4-4193-baa2-fc544b1b1f4e/ACIL-draft-methodology-report-estimating-energy-pu.aspx
[9] https://www.escosa.sa.gov.au/ArticleDocuments/775/120928-WholesaleElectricityCostInvestigationApproach-ACILTasmanReport.pdf.aspx?Embed=Y

consequence, there are considerable difficulties in using the price of PPAs or the annualised historical cost of generation as a basis for estimating current hedging costs.

Components of the WEC

In estimating the wholesale energy costs incurred by a prudent and efficient retailer, it is generally assumed that the retailer is partly exposed to the wholesale spot market and partly protected through a contract hedging strategy.

The market-based approach includes an assumed contracting strategy that a prudent retailer would use to manage its electricity market risks or some estimation of contract premiums. Such risks and the strategy used to mitigate them are an important part of electricity retailing.

The WEC for a given year is therefore generally a function of four components:

1. load profile
2. wholesale electricity spot prices
3. forward contract prices
4. contracting strategy.

Variations of the market-based approach

There are generally two variations of the market-based approach:

1. A detailed approach used by the QCA (as well as adopted by ESCOSA and IPART prior to deregulation) which relies on forecasting the load shape, wholesale electricity spot prices, published contract prices and a hedging strategy.
2. A simplified approach used, up until 2018-19, by the ICRC which relies on the historical load shape, the historical relationship between load shape and spot prices, and published contract prices.

The key difference between the two approaches is that the ICRC approach does not rely on spot market modelling or determining an efficient hedging strategy.

There may be other variations of the market-based approach not recently considered or adopted by regulators. One such approach, which ACIL Allen proposes be explored for the purpose of the DMO is very simple, and relies on the movement in the portfolio of contract prices from one determination year to the next.

Detailed approach

The key steps to the detailed approach for estimating the WEC for a given load and year are:

1. Forecast the half-hourly load profile – generally as a function of the underlying demand forecast as published by AEMO, and accounting for further uptake of rooftop solar PV.
2. Forecast half-hourly wholesale electricity spot prices – the wholesale electricity spot price is generally forecast by simulating the NEM using a proprietary wholesale energy market model.
3. Assume a contracting strategy – the contracting strategy represents a strategy that a prudent and efficient retailer would undertake to hedge against risk in the spot price in a given year. It is generally assumed that a prudent and efficient retailer's risk management strategy would result in contracts being entered into progressively over a two- or three-year period, resulting in a mix (or portfolio) of base (or flat), peak and cap contracts.
4. Estimate the forward contract price – the forward contract prices are generally estimated from publicly available data. The use of publicly available data implicitly assumes that the value of any bilateral contracts entered into by the prudent and efficient retailer are based on the value of OTC and futures contracts.
5. Calculate the spot and contracting cost for each half hour and aggregate – for each half hour calculate the spot purchase cost, contract purchase costs, and different payments, and then aggregate to get an annual cost which is divided by the annual load to get a price in $/MWh terms.

The 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 market data.

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

The above steps produce a single estimate of the WEC. The actual value of the WEC may vary due to variations in demand, and spot prices that eventuate for the given year. Wholesale electricity spot prices will vary depending on the actual load (which will vary based on weather conditions), renewable generator resource (which also varies with weather outcomes), and availability of thermal power stations. It is this variability, and associated risk, that incentivises retailers to enter into hedging arrangements. However, this variability also changes the values of the spot purchase costs and difference payments incurred by a retailer (even though the contract prices and strategy are fixed).

Therefore, it is important to estimate the WEC under a range of plausible sensitivities. As such, a number of simulations are generally run to understand the range of potential outcomes. This usually involves utilising:

1. A stochastic demand model to develop multiple weather influenced simulations of hourly demand traces for each of the tariff profiles.
2. A stochastic outage model to develop multiple power station availability simulations.
3. An energy market model to run multiple simulations of hourly spot prices of the NEM using the stochastic demand and renewable energy resource traces and power station availabilities as inputs.
4. An analysis of contract data to estimate contract prices using the ASX Energy contract price data, verified with broker data. The book build is based on the observed trade volumes and the price estimate is equal to the trade volume weighted average price.
5. A hedge model taking the above analyses as inputs to estimate a distribution of hedged prices for different hedging strategies and choosing a suitable hedging strategy.
6. Undertaking a final run of the hedge model for the simulations taking the above analyses as inputs, together with the finalised hedge strategy to estimate a distribution of hedged prices for the given load profile.

The distribution of outcomes produced by the above approach is then analysed to provide a risk assessed estimate of the WEC. For the QCA, ACIL Allen adopts the 95th percentile WEC from the distribution of WECs as the final estimate. In practice, the distribution of WECs from the simulations exhibits a narrow spread, which is to be expected since they are hedged values. Choosing the 95th percentile reduces the risk of understating the true WEC.

As mentioned above, multiple hedging strategies are tested by varying the mix of base/peak/cap contracts for each quarter. The hedging strategy that results in the lowest 95th percentile WEC is adopted. In our work for the QCA, the hedging strategy is not necessarily varied for every determination year – it tends to change when there is a sufficient change in either the shape of the load profile (for example, due to the continued uptake of rooftop PV) or a change in the relationship between contract prices for the different contract products (for example, in some years base contract prices increase much more than peak contract prices, which can influence the strategy).

The previous ICRC approach

The ICRC considers the modelling of forecast wholesale electricity spot prices to be too complex. Consequently, it developed an approach to estimating the energy cost that it considered to be simpler. The approach does not rely on proprietary energy market models. The ICRC model is well described in the Commission's *Final Technical Paper: Model for Determining the Energy Purchase Cost Component of the Transitional Franchise Tariff* (March 2010).

It estimates the energy purchase costs (EPC) for a given load for a given period of time. The model assumes that the retailer employs a very simple hedging strategy that results in all load, in a given quarter, being covered by a base or flat contract. The level of hedging is therefore equal to the peak half-hourly load in the quarter. Given that the load factor of any collection of customers is rarely equal to one (with the exception of some industrial loads) there will be half hours in which the level of contract cover is in excess of the actual load. In these instances, the excess contracts are on-sold to the market at the going spot price for the given half-hour.

The model was reviewed in 2018-19, and the outcome of that review was to adopt an approach more similar to the detailed approach, including a prudent hedging strategy based on a portfolio of hedging products. For this reason, we do not consider the previous ICRC approach to estimating the WEC further in this report.

Portfolio contract price index approach

The portfolio contract price index approach is based on the view that the main driver in movements in the WEC from one year to the next is the change in contract prices. Similar to the detailed approach, this approach assumes a retailer will enter into a portfolio of contracts to manage price risk. However, the portfolio contract price index approach assumes that there is no change in load shape, underlying relationship between spot prices and load, or the extent of spot price exposure from one year to the next. The approach is limited in that it does not estimate an absolute value for the WEC, but rather the relative movement in the WEC from one year to the next.

To explore this approach further, we have used the estimated WECs for the past seven QCA determinations, and the associated contract prices. Figure 3.1 shows the annual percentage change in WEC for the four load profiles as estimated by ACIL Allen using the detailed approach for the QCA. The four load profiles are the:

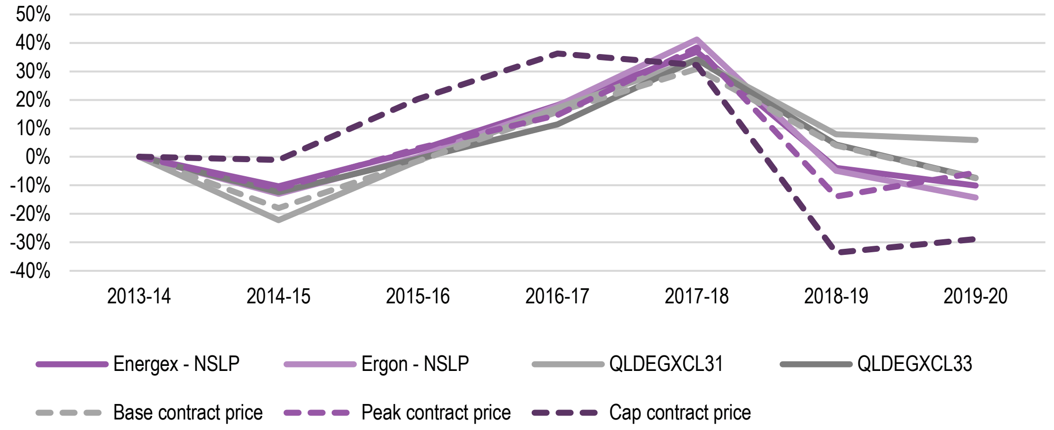
— Energex NSLP
— Ergon NSLP
— Controlled Load Tariff 31 (QLDEGXCL31)
— Controlled Load Tariff 33 (QLDEGXCL33).

Included in Figure 3.1 are the annual percentage changes in price of each of the contract products used in the detailed approach. For this analysis we have used the same trade weighted contract prices for each quarter as was used in the given determination and averaged these based on the number of days in each quarter.[10] There is generally a strong correlation between the annual percentage changes in WEC and contract prices – although the correlation with cap prices is demonstrably weaker.

However, the annual percentage change in WECs is not the same for each load profile – reflecting the different influence of the different hedge products. For example, the controlled loads tend to be less influenced by movements in cap prices, which is not surprising given the majority of controlled load volume occurs in the early hours of the morning when price volatility has been at its lowest.

[10] It would also be possible to weight the quarterly values by the volume of the adopted hedging strategy.

FIGURE 3.1 ANNUAL CHANGE (%) IN WEC ESTIMATES BASED ON THE DETAILED APPROACH FOR THE QCA VERSUS ANNUAL CHANGE (%) IN CONTRACT PRICES



SOURCE: ACIL ALLEN ANALYSIS, QCA REPORTS

Using the data from Figure 3.1 it is possible to calculate a regression to predict the annual percentage change in WEC using the percentage changes in base, peak and cap contract prices as the dependent variables.

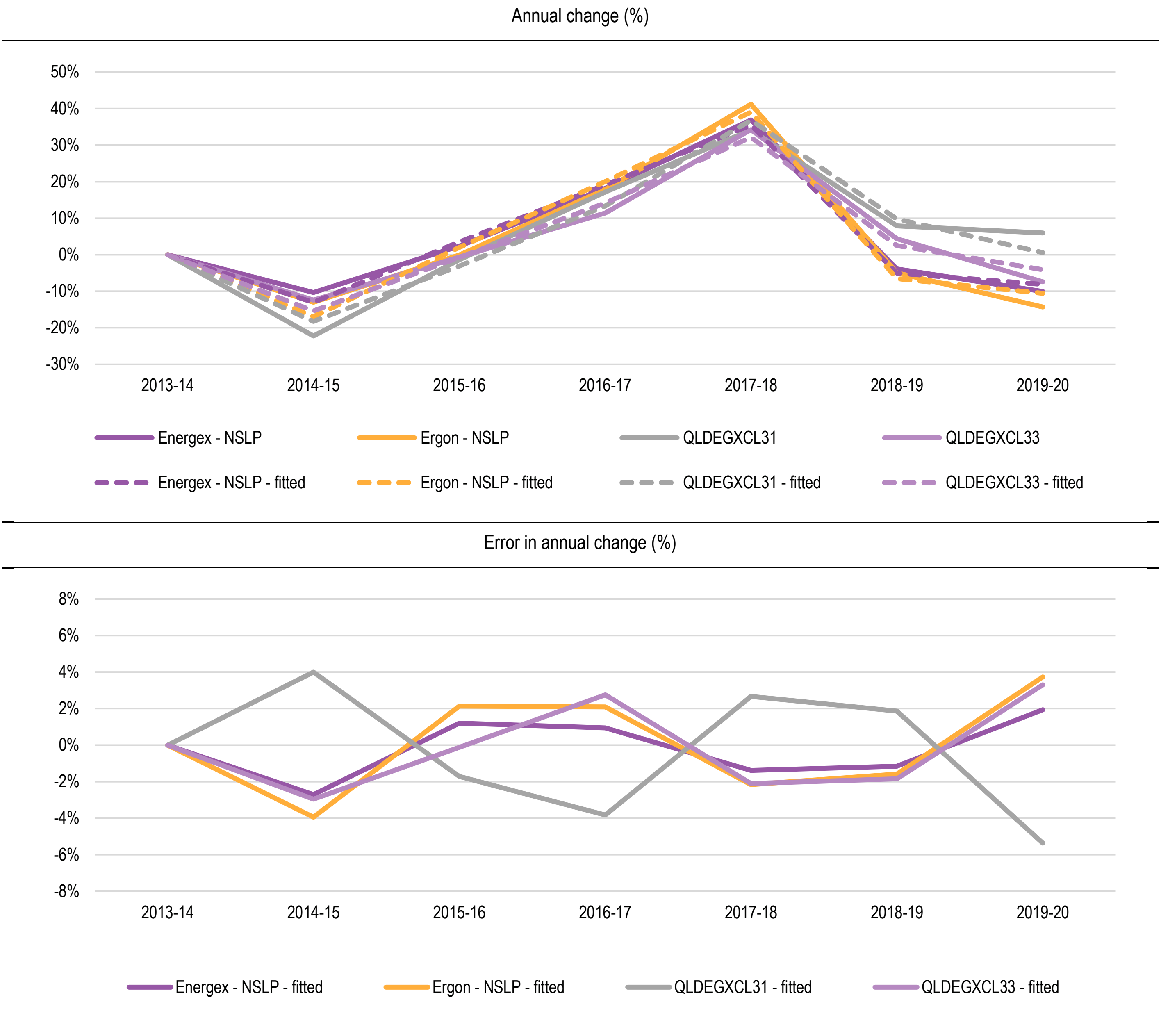
Figure 3.2 compares the actual percentage change in WEC with the fitted change in WEC based on movements in contract prices:

— the first graph compares the percentage changes

— the second graph shows the error in fit.

Movement in contract prices is a strong predictor of the change in WEC – with the fitted WEC changes accounting for about 98 to 99 percent of the variation in actual changes in WEC. However, the approach does not give a perfect fit – in some years the estimated changes in WEC are higher or lower than the actual changes. The residual ranges between +/- five per cent. This may seem small – but when the actual WEC is moving by +/- 10 per cent, this represents a not inconsequential error.

FIGURE 3.2 ANNUAL CHANGE (%) IN WEC ESTIMATES BASED ON THE DETAILED APPROACH FOR THE QCA VERSUS ANNUAL CHANGE (%) IN PORTFOLIO OF CONTRACT PRICES (REGRESSION)

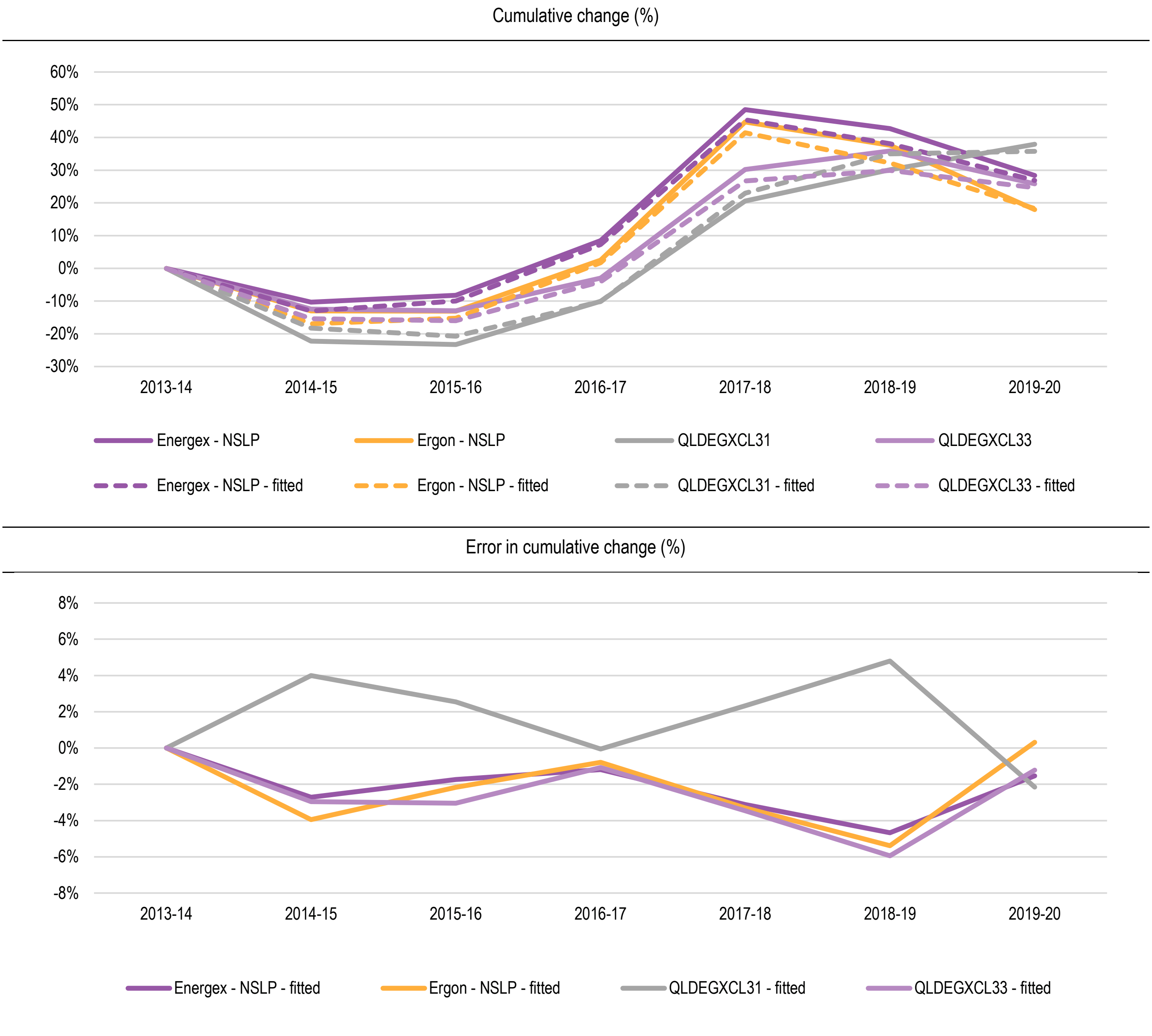


SOURCE: ACIL ALLEN ANALYSIS, QCA REPORTS

Figure 3.2 compared the year on year percentage changes in WEC. Figure 3.3 compares the cumulative actual percentage change in WEC with the cumulative fitted change in WEC based on movements in contract prices, using 2013-14 as the base.

The purpose of Figure 3.3 is to test whether the annual error in estimates compounds over time if the simplified approach was adopted for six years in succession. As expected, there is some compounding of the error over time – but because the year on year errors are both positive and negative, the errors cancel out to some degree over time.

FIGURE 3.3 CUMULATIVE CHANGE (%) IN WEC ESTIMATES BASED ON THE DETAILED APPROACH FOR THE QCA VERSUS CUMULATIVE CHANGE (%) IN PORTFOLIO OF CONTRACT PRICES (REGRESSION)



Note: WEC in 2013-14 set as base.

SOURCE: ACIL ALLEN ANALYSIS, QCA REPORTS

To construct a regression equation of the change in WEC given the change in contract prices requires at least three years of data. If three years of data is not available then another approach is to calculate the weighted average change in contract prices from one year to the next, using the contract strategy to infer the weightings.

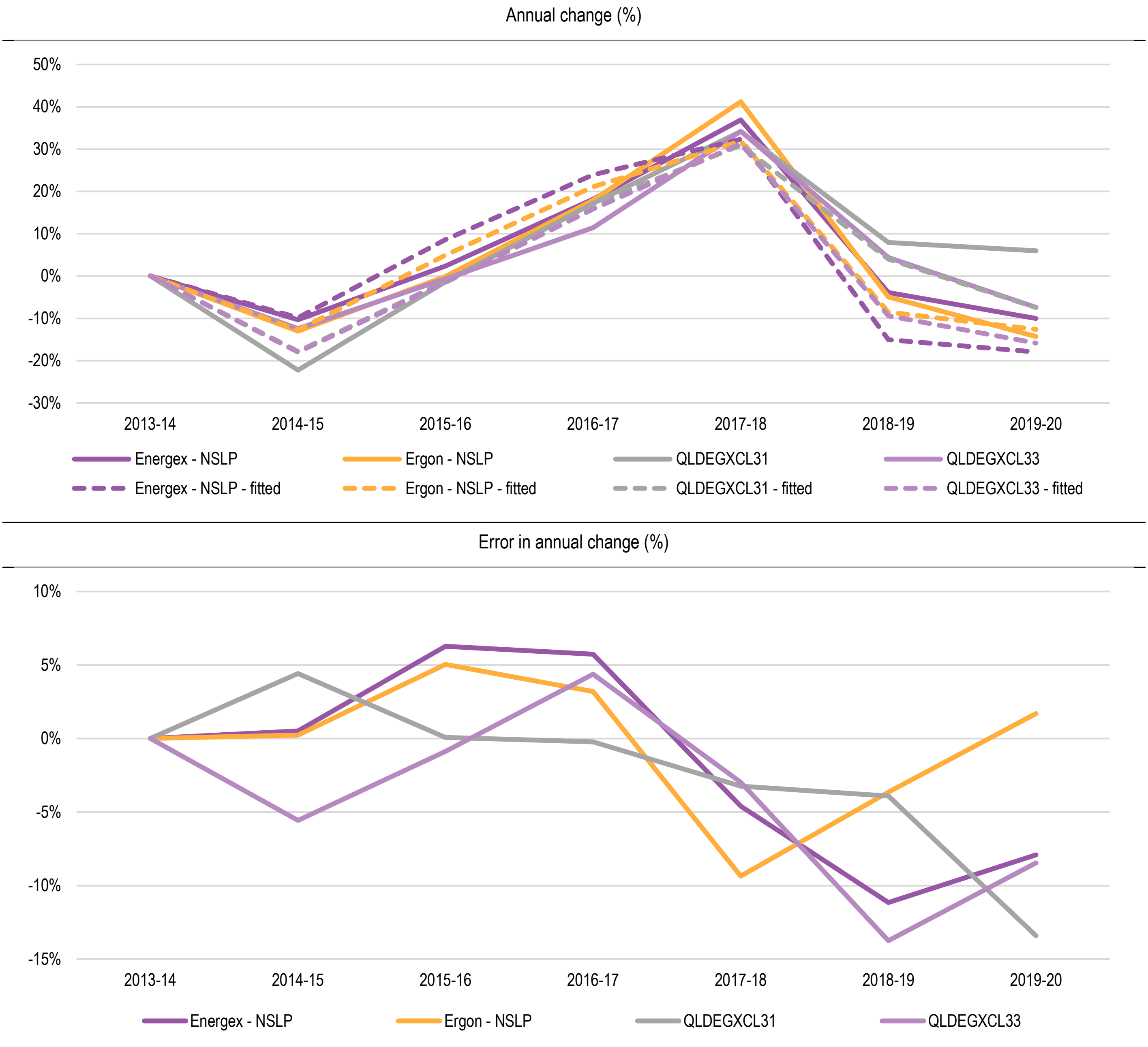
Figure 3.4 compares the actual percentage change in WEC with the estimated change in WEC based on the weighted average movements in contract prices:

— the first graph compares the percentage changes

— the second graph shows the error in estimate.

The annual weighted average movement in contract prices is also a strong predictor of the change in WEC – with the estimated WEC changes accounting for about 94 to 97 percent of the variation in actual changes in WEC. However, the weighted average approach does not give as strong a fit as the regression approach. This is mainly because the regression approach will account for trends in the change in the load shape and residual spot price risk in the observed WECs – whereas the weighted average approach in effect assumes a constant load shape and residual spot price risk from one year to the next.

FIGURE 3.4 ANNUAL CHANGE (%) IN WEC ESTIMATES BASED ON THE DETAILED APPROACH FOR THE QCA VERSUS ANNUAL CHANGE (%) IN PORTFOLIO OF CONTRACT PRICES (WEIGHTED AVERAGE)



SOURCE: ACIL ALLEN ANALYSIS, QCA REPORTS

3.2 Environmental costs

Environmental costs broadly consist of two components:

- scheme targets
- scheme certificate prices.

Estimating the targets is straightforward because this information is published by the relevant jurisdiction's regulator.

Generally, there are two approaches to estimating the certificate prices:

- cost-based approach
- market-based approach.

The approach for each environmental scheme is discussed in the following sections.

3.2.1 Large-scale Renewable Energy Target (LRET)

By 31 March each compliance year, the Clean Energy Regulator (CER) publishes the Renewable Power Percentage (RPP), which translates the aggregate LRET target into the number of Large-scale Generation Certificates (LGCs) that liable entities must purchase and acquit under the scheme.

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 electricity tariffs.

Estimating the RPP is relatively straightforward and involves using the following:

- the CER-published RPP for the current compliance year
- mandated LRET targets for future compliance years as published by the CER.

There are two broad approaches to estimating the LGC price:

- a theoretical long run marginal cost (LRMC) approach
- a market-based approach.

For the reasons outlined in section **3.1.1** above, we do not consider the LRMC approach further in relation to the LRET.

The market-based approach

The market-based approach assumes that an efficient and prudent electricity retailer builds up LGC coverage over a specified period (e.g. two years prior to the determination period).

This approach involves estimating the average LGC price using LGC forward prices, which are available from a number of brokers. The approach used in the past seven QCA determinations involves averaging the forward prices for the calendar years in the determination period during the two years leading up to the commencement of the determination period.

The approach adopted by the AEMC in the 2018 electricity price trends report was based on modelling by EY. In its methodology report[11], EY estimates the LGC price for a small retailer based on the market-based approach, and for a large retailer based on a broad estimate of historically published PPA prices and the effective residual value of LGCs considering the energy market price. The arguments against using the approach used for large retailers in the AEMC report are similar to those against using the LRMC approach, which was discussed in section **3.1.1**.

[11] https://www.aemc.gov.au/sites/default/files/2018-12/EY%20-%202018%20Residential%20Electricity%20Price%20Trends%20-%20Wholesale%20Market%20Cost%20Modelling%20-%20CLEAN.pdf, pp. 31-33.

Estimating costs separately for small and large retailers would be inconsistent with the preferred approach for estimating the WEC (which does not distinguish between small and large retailers). Therefore, we do not consider this approach further in this report.

3.2.2 Small-scale Renewable Energy Scheme (SRES)

Similar to the LRET, by 31 March each compliance year, the CER publishes the binding Small-scale Technology Percentage (STP) for a year and non-binding STPs for the next two years.

The STP is determined ex-ante by the CER and represents the relevant year's projected supply of Small-scale Technology Certificates (STCs) as a percentage of the estimated volume of liable electricity consumption throughout Australia in that year.

The estimated cost of compliance with the SRES is derived by applying the estimated STP value to the STC price.

Estimating the STP for the first three calendar years is relatively straightforward and involves using binding and non-binding STP values, as published by the CER.

Estimating the STP for subsequent years involves analysing and modelling the SRES to produce projections of STCs created in a given year based on projected uptake of small-scale systems across Australia.

The approach used in the past seven QCA determinations involves using the STC clearing house price of $40 per STC and applying this to the estimated STP in a given year.

The approach adopted by the AEMC in the 2018 electricity price trends report was based on modelling by EY. In its methodology report[12], EY estimates the STC price for a small retailer based on the clearing house price of $40 and for a large retailer based on a discounted cost of $35. EY's rationale for departing from the clearing house price is that large retailers can acquire large volumes of STCs at a discount.

Estimating costs separately for small and large retailers would be inconsistent with the preferred approach for estimating the WEC (which does not distinguish between small and large retailers). Therefore, we do not consider this approach further in this report.

3.2.3 New South Wales Energy Savings Scheme (ESS)

The Energy Savings Scheme (ESS) is a New South Wales Government program to assist households and businesses reduce their energy consumption. It is a certificate trading scheme in which retailers are required to fund energy efficiency through the purchase of certificates.

In the 2013 NSW review of regulated retail prices for electricity[13], IPART estimated the cost of the ESS by multiplying the energy savings target, which is published on the EES website, with the estimated cost of an Energy Savings Certificate (ESC). IPART used the base penalty price as a proxy for the ESC price, due to the lack of depth in the observed spot market for ESCs. This approach was generally accepted by stakeholders.

In the AEMC's 2018 price trends methodology report, the estimated cost of the ESS appears to be based on market prices for ESCs. [14]

In the AEMC's report, the estimated cost of ESS, which is expected to be generally flat over the reporting period, comprises less than 10 per cent of the cost of environmental policies, and less than 1 per cent of the total retail bill in NSW during the four-year reporting period.

[12] https://www.aemc.gov.au/sites/default/files/2018-12/EY%20-%202018%20Residential%20Electricity%20Price%20Trends%20-%20Wholesale%20Market%20Cost%20Modelling%20-%20CLEAN.pdf, pp. 33-34.
[13] https://www.ipart.nsw.gov.au/files/sharedassets/website/trimholdingbay/final_report_-_review_of_regulated_retail_prices_for_electricity_-_from_1_july_2013_to_30_june_2016.pdf
[14] Table 8.5, page 49 at https://www.aemc.gov.au/sites/default/files/2018-12/AEMC%202018%20Residential%20Electricity%20Price%20Trends%20Methodology%20Report%20-%20CLEAN.pdf

ACIL Allen notes that ESC forward prices and trade volumes are available from brokers, such as, Demand Manager. Consistent with the market-based approach used for other components, we do not consider the approach that uses the penalty to estimate the ESC price further in this report.

3.2.4 South Australia Retailer Energy Efficiency Scheme (REES)

The Retailer Energy Efficiency Scheme (REES) is a South Australian Government energy efficiency scheme that provides incentives for South Australian households and businesses to save energy. It does this via energy efficiency and audit targets to be met by electricity and gas retailers with customers in South Australia.

In the AEMC's 2018 price trends methodology report, the cost of the REES was sourced using data from the relevant jurisdiction, although there is no link to the exact location of this data.[15]

In the AEMC's report, the estimated cost of REES, which is expected to be generally flat in nominal terms over the reporting period, comprises less than 10 per cent of the cost of environmental policies, and less than one per cent of the total retail bill in South Australia during the four-year reporting period.

Given the limited availability of public data on the cost of meeting the REES and given that the cost as estimated by AEMC is a very small component of the overall cost of the retail bill, ACIL Allen proposes to use the estimates of the cost of REES provided in the latest AEMC price trends report.

3.3 Other costs

The approach to estimating other costs is straightforward because most of the data used to estimate them are based on actual costs which are readily available from AEMO.

3.3.1 Market fees

The current approach used in the QCA determinations for estimating market fees is to make use of AEMO's budget report. For the most part, the budget report includes forecasts of fees for four or more years. This approach is also used in the 2018 AEMC price trends report[16].

3.3.2 Ancillary service costs

The current approach used in the QCA determinations for estimating ancillary services costs is to average the most recent 52 weeks of costs to recover ancillary services from customers, which is published on the AEMO website.

The approach used in the 2018 AEMC price trends report is to extrapolate to future years with a linear trend using the past two years of actual cost data from AEMO[17].

On an annual average basis, ancillary services costs have been relatively flat. Hence the difference between the two approaches would be negligible.

3.3.3 Prudential costs

The current approach used in the QCA determinations is to use AEMO's volatility factors and ACIL Allen's spot price projections to determine the cost of a retailer funding a bank guarantee for the AEMO-assessed maximum credit limit. The approach also involves using the ASX Energy initial margin parameters and ASX Energy futures contract price data to determine the cost to a retailer of funding initial margins.

[15] Table 8.5, page 49 at https://www.aemc.gov.au/sites/default/files/2018-12/AEMC%202018%20Residential%20Electricity%20Price%20Trends%20Methodology%20Report%20-%20CLEAN.pdf
[16] https://www.aemc.gov.au/sites/default/files/2018-12/AEMC%202018%20Residential%20Electricity%20Price%20Trends%20Methodology%20Report%20-%20CLEAN.pdf, p.31.
[17] https://www.aemc.gov.au/sites/default/files/2018-12/AEMC%202018%20Residential%20Electricity%20Price%20Trends%20Methodology%20Report%20-%20CLEAN.pdf, pp.30-31.

AEMO publishes volatility factors two years in advance. Similarly, ASX Energy publishes initial margin parameters two years in advance.

There is limited information available about other approaches to estimating prudential costs because they have not been considered in determinations in jurisdictions other than Queensland.

As discussed earlier in section **2.3**, it is possible that the AEMC implicitly includes prudential costs within the so-called residual component of the retail tariff. Therefore, the AER needs to take care not to double count this cost when determining the DMO.

3.3.4 Energy losses

Based on the approach used in the QCA determinations, estimated energy losses are applied to the wholesale energy costs (including the environmental and other costs). The loss factors used are published by AEMO one year in advance – marginal loss factors (MLFs, for transmission) and distribution loss factors (DLFs), for all NEM regions.

Average transmission losses by network area are estimated by allocating each transmission connection point to a network based on their location. Average distribution losses are already summarised by network area in the AEMO publication

A similar approach is used in the 2018 AEMC price trends report.

4 IDENTIFY EVALUATION PRINCIPLES

Before assessing the different approaches and contemplating modifications, a set of evaluation principles ought to be considered.

In determining the DMO, the Competition and Consumer (Industry Code – Electricity Retail) Regulations 2019 (the Regulations) requires the AER to determine the annual consumption and annual retail bill amounts based on the following principles and policy objectives:

- an electricity retailer should be able to make a reasonable profit in relation to supplying electricity in the region
- to reduce the unjustifiably high level of standing offer prices for consumers who are not engaged in the market
- to set DMO prices at a level that provides consumers and retailers with incentives to participate in the market
- to allow retailers to recover their efficient costs in servicing customers.

The overall objective of estimating the DMO is to ensure that the projected change in costs is as accurate as possible.

4.1 AER pricing principles

The AER provided ACIL Allen with the following pricing principles which provides guidance when considering the methodology:

- **Accuracy and reliability**
  - The AER considers a technique is accurate when it produces unbiased results and is reliable when it produces consistent results. Objective techniques (based on actual data) are inherently more accurate than subjective techniques (based on judgement); they are less susceptible to bias and therefore others can judge them fairly. Reliable techniques should produce similar results under consistent conditions. In some cases, techniques may require testing and calibration for the AER to be satisfied of their accuracy and reliability.
- **Robustness**
  - Robust techniques remain valid under different assumptions, parameters and initial conditions. However, the AER also considers robust techniques must be complete. A technique that is lacking in some material respect cannot be robust.
- **Transparency**
  - A technique that the AER or stakeholders are unable to test (sometimes referred to as a ‘black box’) is not transparent because it is not possible to assess the results in the context of the underlying assumptions, parameters and conditions.
- **Fitness for purpose**

  - The AER considers it is important to use the appropriate technique for the task. No technique that regulators rely on can produce a perfect forecast. However, the regulations do not require the AER to produce precise estimates. Rather, the AER must be satisfied the forecast reasonably achieves the policy objectives. Accordingly, the AER will consider fitness for purpose in this context.
- **Predictability and stability**
  - Consistency, both over time and across jurisdictions, in the methods used in setting retail prices provides stability and predictability for the retail sector.
  - Predictability and stability do not preclude changes in the regulatory and policy environment; some flexibility will be required to accommodate changes in market or external conditions. These changes should be transparent and based on well-understood objectives.
- **Appropriate allocation of risk**
  - The methods associated with setting cost components should reflect the appropriate allocation of risk between retailers and customers. Risks should always be allocated to the party that is best able to manage that risk. Further, the method should reflect, and be commensurate with, the level of risk that the relevant party faces. If the risks are unmanageable, or cannot be mitigated, then mechanisms should be put in place to allocate the risk to the party who can best bear them.
- **Parsimony**
  - Multiple techniques may be able to provide the same information, but to varying degrees of accuracy and with varying degrees of complexity. The AER will typically prefer a simpler technique (or one with fewer free parameters) over more complex techniques, if it measures equally against other principles. Where possible, the AER intends to move away from assessment techniques that draw the AER and stakeholders into unnecessary detail when there are alternative techniques.

4.2 Additional considerations for wholesale and environmental cost estimation approaches

In addition to using the pricing principles as a guide, the methodology should:

1. reflect the best available forecast methodology to assess changes that broadly reflect changes in wholesale and environmental costs for an efficient electricity retailer
2. enable the assessment of the changes in wholesale and environmental costs for each customer type.

Further, along with any traditional detailed forecasting methodologies, the AER requires us to consider the merits of a more simplified forecasting approaches.

5 ASSESSMENT OF DIFFERENT APPROACHES

In this chapter we assess each of the considered approaches against the principles and guidelines presented in Chapter **4**.

5.1 Wholesale Energy Cost (WEC)

The following two WEC estimation approaches are evaluated:

— the detailed approach
— the portfolio contract price index approach.

5.1.1 Pricing principles

Accuracy and reliability

— Principle: A technique is considered accurate when it produces unbiased results and is reliable when it produces consistent results. Objective techniques (based on actual data) are inherently more accurate than subjective techniques (based on judgement); they are less susceptible to bias and therefore others can judge them fairly. Reliable techniques should produce similar results under consistent conditions. In some cases, techniques may require testing and calibration for the AER to be satisfied of their accuracy and reliability.

  – Assessment – Detailed approach:

    - Application of the detailed approach for the QCA and other regulators (prior to deregulation) has demonstrated its ability to produce unbiased and reliable estimates of the WEC. The absolute value of, and the movement in, the WECs estimated for the QCA have been intuitive and consistent given the changes in market conditions. Our experience when working with the QCA is that retailers have expressed concern that the estimates of the WEC were too low for about half of the past determinations, and consumer advocacy groups have expressed concern that the WEC estimates were too high for the other half of the determinations. Crudely, this suggests the method is producing reasonable estimates.

  – Assessment – Portfolio contract index approach:

    - Although the portfolio contract index approach produces unbiased estimates in the percentage change in WEC from one years to the next, it cannot produce absolute estimates of the WEC. Further, it relies on the establishment of a relationship between WEC and contract prices – therefore, it requires either of the other methods to be applied initially (for say three years) so that a relationship between WEC and price movements can be established.

Robustness

- Principle: Robust techniques remain valid under different assumptions, parameters and initial conditions. However, the AER also considers robust techniques must be complete. A technique that is lacking in some material respect cannot be robust.
  - Assessment – Detailed approach:
    - Despite the detailed approach being a simplification of how retailers incur costs when retailing electricity, it is more detailed than the other approaches and attempts to meaningfully mimic the way retailers think about and manage risk. The approach does not rely on historical relationships which, given how rapidly the market has been changing in recent years, is an important and positive feature of the approach. It has remained valid over the past eight or so years demonstrating its robustness to changes in the market.
  - Assessment – Portfolio contract index approach:
    - The portfolio contract index approach is relatively robust as it relies on medium term historical relationships, rather than long term relationships. It also takes account price movements in all three contract products, not just base contracts.

Transparency

- Principle: A technique that the AER or stakeholders are unable to test (sometimes referred to as a ‘black box’) is not transparent because it is not possible to assess the results in the context of the underlying assumptions, parameters and conditions.
  - Assessment – Detailed approach:
    - The detailed approach is the least transparent of the three approaches as it relies on the modelling of spot prices, and projecting the change in load shape. That being said, the level of transparency is improved by providing informative summaries of the modelling to allow stakeholders to scrutinise the results (which is the approach adopted by the QCA).
  - Assessment – Portfolio contract index approach:
    - The portfolio contract index approach is fully transparent once the relationship between historical WEC and contract price movements has been established.

Fitness for purpose

- Principle: The AER considers it is important to use the appropriate technique for the task. No technique that the AER or other regulators rely on can produce a perfect forecast. However, the regulations do not require the AER to produce precise estimates. Rather, the AER must be satisfied the forecast reasonably achieves the policy objectives. Accordingly, the AER will consider fitness for purpose in this context.
  - Assessment – Detailed approach:
    - The detailed approach uses the 95th percentile hedged price outcome as the final estimate for the WEC. The 95th percentile is chosen not to improve the accuracy of the estimate but rather to minimise the chance of understating the risk associated procuring wholesale electricity to serve retail load and therefore disincentivising retailers from participating in the market. This is in itself achieves the key policy objectives.
  - Assessment – Portfolio contract index approach:
    - The portfolio contract index approach, provided it is applied after the detailed approach has been used, is likely to satisfy the policy objectives and be fit for purpose.

Predictability and stability

- Principle: Consistency, both over time and across jurisdictions, in the methods used in setting retail prices provides stability and predictability for the retail sector.
- Principle: Predictability and stability does not preclude changes in the regulatory and policy environment; some flexibility will be required to accommodate changes in market or external conditions. These changes should be transparent and based on well-understood objectives.
  - Assessment – Detailed approach:

- The detailed approach has been used successfully in a number of regions of the NEM for both NSLP profiles and controlled load profiles. The approach has also been used during periods of substantial change in the market – in terms of policy (such as the carbon tax, and hiatus in renewable investment as a result of the LRET review), as well as changes in the nature of demand and supply (such as the changing load shape due to rooftop PV).
- The detailed approach is adaptable – for example, the hedging strategy can change with a change in load shape or change in the relativities of base/peak/cap contract prices.
- As demonstrated by the analysis of movements in contract prices versus the WEC estimated using the detailed approach, the estimates are predictable to the extent that movements in contract prices are predictable.

– Assessment – Portfolio contract index approach:
  - The portfolio contract index approach is predictable to the extent that contact price movements are predictable.
  - However, it may have difficulty to adapt to substantial step-changes in the market.

Appropriate allocation of risk

— Principle: The methods associated with setting cost components should reflect the appropriate allocation of risk between retailers and customers. Risks should always be allocated to the party that is best able to manage that risk. Further, the method should reflect, and be commensurate with, the level of risk that the relevant party faces. If the risks are unmanageable, or cannot be mitigated, then mechanisms should be put in place to allocate the risk to the party who can best bear them.

– Assessment – Detailed approach:
  - The detailed approach reasonably allocates risk between both retailers and consumers, by assuming retailers are best placed to manage price risk.

– Assessment – Portfolio contract index approach:
  - The portfolio contract index approach reasonably allocates risk between both retailers and consumers, by assuming retailers are best placed to manage price risk. The issue with this approach is that if the nature of the market changes over time then there is a risk of the WEC estimate placing more risk on the retailer.

5.1.2 Best available forecast methodology to assess changes that broadly reflect changes in wholesale and environmental costs for an efficient electricity retailer

It is our opinion that the detailed approach provides the best estimate of the WEC and changes in WEC, for reasons discussed in the previous section. The portfolio contract index approach is also equally likely to provide reasonable estimates of the change in WEC from one year to the next (provided the relationship between WEC and contract prices is already established).

5.1.3 Enables the assessment of changes in wholesale and environmental costs for each customer type

The detailed approach and portfolio contract index approach will allow the AER to assess changes in the WEC for each customer type.

5.1.4 Summary assessment of WEC approaches

Taking the above assessments for the different WEC estimation approaches, Table 5.1 provides a quick visual summary of the assessments using a traffic light rating system.

On balance, the detailed approach is more likely to provide a more accurate estimate of the wholesale energy costs incurred by a retailer. However, it is more complex and less transparent – although this can be mitigated by providing meaningful summaries of the outputs for stakeholder scrutiny.

The portfolio contract index approach has some merit in that it is very transparent and predictable. However, it would rely on pre-existing WEC estimates.

On balance, our recommended approach for the WEC component is to consider using the detailed approach for the next three or so determinations of the DMO, and then move to the portfolio contract index approach (using regression) for the subsequent three or so determinations; and repeat this pattern (noting that the pattern may change depending on circumstances in the market). This strikes a balance between accuracy, transparency, predictability and simplicity.

If the detailed approach is used for one or two years and then the portfolio contract index approach is used then the weighted average change in contract prices would need to be calculated rather than regressing the change in WEC against the change in contact prices due to insufficient data points.

TABLE 5.1 ASSESSMENT OF WEC ESTIMATION APPROACHES WITH PRICING PRINCIPLES AND ADDITIONAL CONSIDERATIONS

	Detailed approach	Contract portfolio index approach
Pricing principles		
– Accuracy and reliability	🟢	🟡
– Robustness	🟢	🟡
– Transparency	🟡	🟢
– Fit for purpose	🟢	🟡
– Predictability and stability	🟡	🟢
– Appropriate allocation of risk	🟢	🟢
– Overall assessment against pricing principles	🟢	🟡
Additional evaluation principles		
– reflect best available forecast methodology to assess changes that broadly reflect changes in wholesale costs for an efficient retailer	🟢	🟡
– enable the assessment of the changes in wholesale and environmental costs for each customer type	🟢	🟢

Note: 🟢 = strong evidence; 🟡 = some evidence; 🔴 = limited or nil evidence.

SOURCE: ACIL ALLEN

5.2 Environmental costs

For the reasons outlined in section **3.2**, we consider that only the market-based approach to estimating the environmental costs can be considered.

5.3 Other costs

For the reasons discussed in section **3.3**, we consider that the market-based approach to estimating other costs meets is the only approach available.

6

PROPOSED APPROACH

In this chapter we provide details of the proposed approach to estimating the wholesale and environmental costs.

Although in the previous chapters we have already provided some details of the different approaches, and our assessment, the purpose of this chapter is to drill down into the methodology of the proposed approach, and its subcomponents, as there remain some details that need to be explored and finalised. This is particularly the case for the WEC.

6.1 Wholesale energy costs

6.1.1 Overview

ACIL Allen proposes the detailed market-based approach for estimating the WEC be considered for the next three or so years of the DMO, followed by the contract portfolio index approach for the subsequent three or so years, along the lines of:

- Determination year 1:
  - use detailed market-based approach to estimate WEC values for each load profile.
- Determination year 2:
  - use detailed market-based approach to estimate WEC values for each load profile.
- Determination year 3:
  - use detailed market-based approach to estimate WEC values for each load profile.
- Determination year 4:
  - estimate relationship between movement in the WECs and the movement in contract prices from the previous three determinations for each load profile
  - calculate observed movement in contract prices between year 3 and 4
  - use relationship together with observed movements in contract prices between years 3 and 4 to estimate movement in WECs between years 3 and 4.
- Determination year 5:
  - use the established relationship between movement in the WECs and the movement in contract prices together with observed movements in contract prices between years 4 and 5 to estimate movement in WECs between years 4 and 5 for each load profile.
- Determination year 6:
  - use the established relationship between movement in the WECs and the movement in contract prices together with observed movements in contract prices between years 5 and 6 to estimate movement in WECs between years 5 and 6 for each load profile.

As mentioned in section 5.1.4, if the above sequence is shortened such that the detailed approach is used for one or two years and then the portfolio contract index approach is used, then the portfolio contract index approach would need to rely on the weighted average change in contract prices rather than regressing the change in WEC against the change in contact prices due to insufficient data points.

6.1.2 Sources of consideration for the detailed market-based approach

In terms of the recommended details of the market-based approach, we consider three sources:

1. ACIL Allen's approach for the QCA for the 2012-13 to 2019-20 regulated retail price determinations[18]
2. EY's approach for the AEMC for the 2018 residential electricity retail price trends report[19]
3. Frontier's proposed approach for the ESC for the July 2019 Victorian Default Offer[20].

6.1.3 Key step in estimating the WEC

The key steps to the detailed approach for estimating the WEC for a given load and year are:

1. Forecast the half-hourly load profiles – generally as a function of the underlying demand forecast as published by AEMO, and accounting for further uptake of rooftop solar PV, storage and electric vehicles.
2. Forecast the half-hourly renewable energy resource profiles – which are appropriately correlated with each other and demand.
3. Generate half-hourly thermal power station availability simulations.
4. Forecast half-hourly wholesale electricity spot prices – the wholesale electricity spot price is generally forecast by simulating the NEM using a proprietary wholesale energy market model.
5. Estimate forward contract prices – the forward contract prices are generally estimated from publicly available data. The use of publicly available data implicitly assumes that the value of any bilateral contracts entered into by the prudent and efficient retailer are based on the value of OTC and futures contracts.
6. Develop contracting strategy – the contracting strategy represents a strategy that a prudent and efficient retailer would undertake to hedge against risk in the spot price in a given year. It is generally assumed that a prudent and efficient retailer's risk management strategy would result in contracts being entered into progressively over a two- or three-year period, resulting in a mix (or portfolio) of base (or flat), peak and cap contracts.
7. Calculate spot and contracting cost for each half hour and aggregate – for each half hour calculate the spot purchase cost, contract purchase costs, and different payments, and then aggregate to get an annual cost which is divided by the annual load to get a price in $/MWh terms.

6.1.4 Forecast the half-hourly load profiles

The following half hourly load profiles are required for the given determination year:

— System load for each region of the NEM (that is, the load to be satisfied by scheduled and semi-scheduled generation) – used to model the regional wholesale electricity spot prices.

— NSLPs and controlled load profiles (CLPs) - used to model the half-hourly cost of procuring energy for the following:
  - New South Wales: Ausgrid, Endeavour, Essential
  - Queensland: Energex
  - South Australia: SAPN.

Historical load data is available from AEMO – as shown in Table 6.1.

[18] https://www.esc.vic.gov.au/electricity-and-gas/inquiries-studies-and-reviews/electricity-and-gas-retail-markets-review-implementation-2018/electricity-and-gas-retail-markets-review-implementation-2018-victorian-default-offer#toc--final-advice-to-the-victorian-government|tabs-container2

[19] https://www.aemc.gov.au/sites/default/files/2018-12/EY%20-%202018%20Residential%20Electricity%20Price%20Trends%20-%20Wholesale%20Market%20Cost%20Modelling%20-%20CLEAN.pdf

[20] file:///C:/Users/rlenton/Downloads/RPT%20-%20Frontier%20Economics%20-%20Final%20Report%20-%20Wholesale%20electricity%20costs%2020190419%20(2).PDF

TABLE 6.1 SOURCES OF LOAD DATA

Region	Distribution Network	Load Type	Load Name	Source
New South Wales	NA	System Load	NSW1	MMS
	Ausgrid	NSLP	NSLP,ENERGYAUST	MSATS
	Ausgrid	CLP	CLOADNSWCE,ENERGYAUST	MSATS
	Ausgrid	CLP	CLOADNSWEA,ENERGYAUST	MSATS
	Endeavour	NSLP	NSLP,INTEGRAL	MSATS
	Endeavour	CLP	CLOADNSWIE,INTEGRAL	MSATS
	Essential	NSLP	NSLP,COUNTRYENERGY	MSATS
	Essential	CLP	CLOADNSWCE,COUNTRYENERGY	MSATS
Queensland	NA	System Load	QLD1	MMS
	Energex	NSLP	NSLP,ENERGEX	MSATS
	Energex	CLP	QLDEGXCL31,ENERGEX	MSATS
	Energex	CLP	QLDEGXCL33,ENERGEX	MSATS
South Australia	NA	System Load	SA1	MMS
	SAPN	NSLP	NSLP,UMPLP	MSATS
	SAPN	CLP	SACLOAD,UMPLP	MSATS

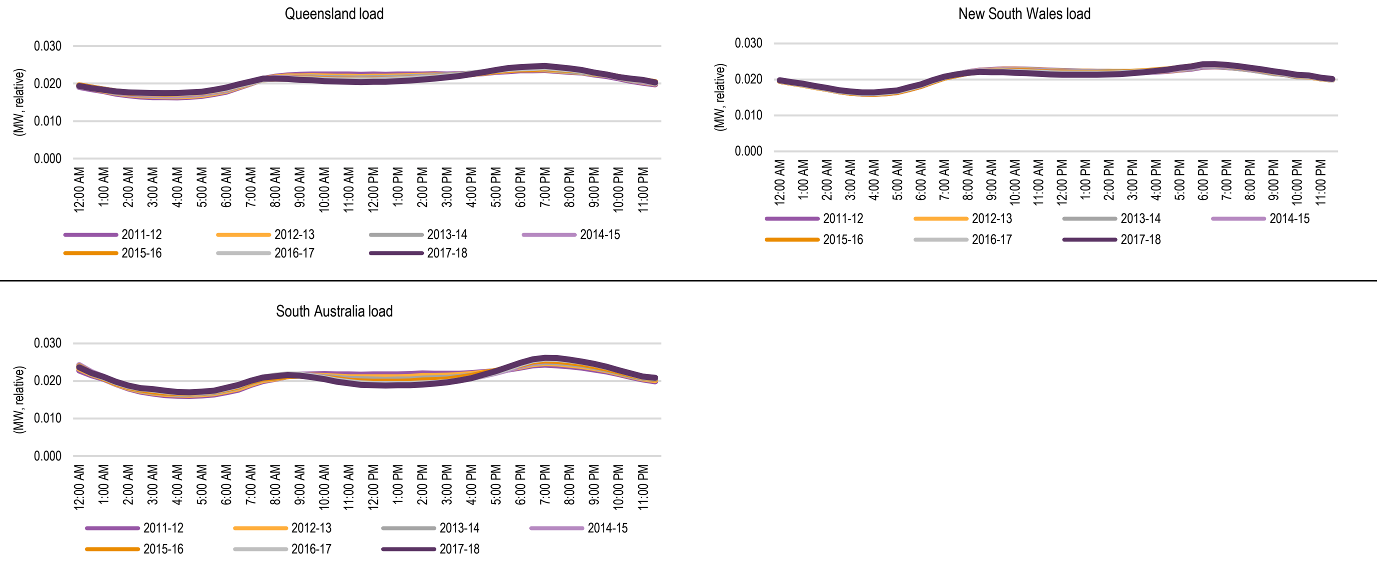
SOURCE: AEMO

Figure 6.1 to Figure 6.4 show the average time of day load system profiles for Queensland, New South Wales and South Australia, as well as the corresponding NSLPs and CLPs (based on the data sources shown in Table 6.1).

Over the past few years, the Queensland and South Australian NSLP load profiles, and to some degree, the New South Wales NSLPs, 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 CLPs are relatively consistent across the different distribution zones – ramping up from about 9:30 pm, peaking at about midnight and then ramping down to about 3:00 am. The outlier is the CLOADNSWIE CLP which exhibits a substantial change in 2016-17 and 2017-18 – resulting in a much flatter profile. It will be worth exploring this with Endeavour Energy so that we understand whether this this change in profile is expected to be permanent.

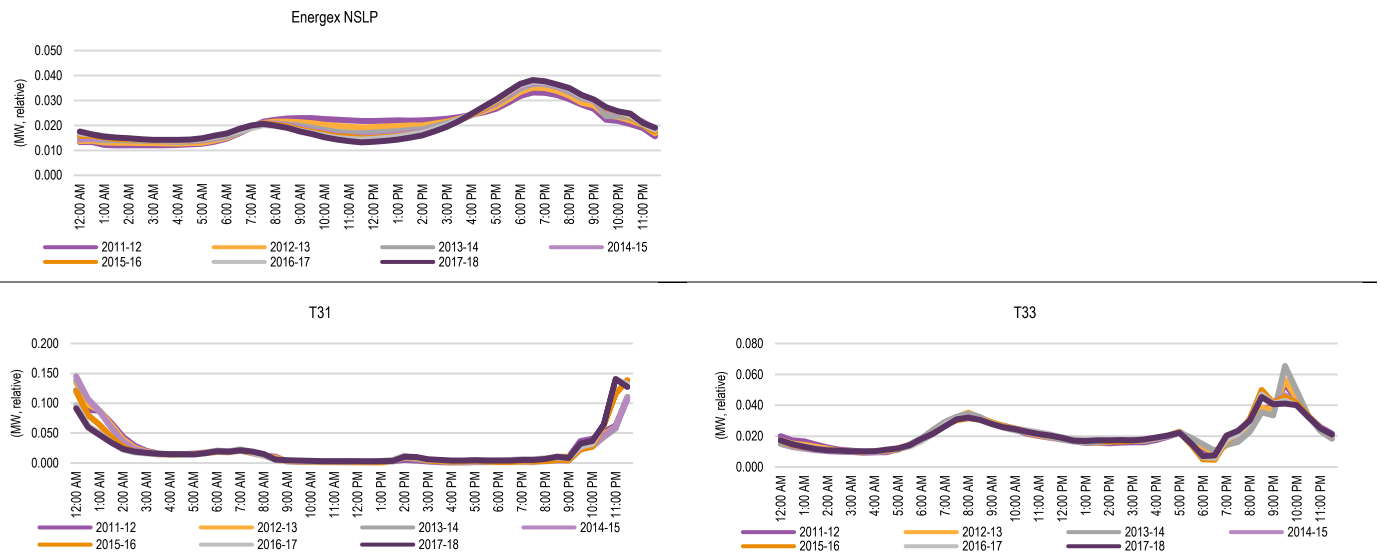
FIGURE 6.1 ACTUAL AVERAGE TIME OF DAY REGIONAL LOAD PROFILE (MW, RELATIVE) – 2011-12 TO 2017-18



Note: The term relative MW means the loads for each year have been scaled so they sum to one. This removes 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.

SOURCE: ACIL ALLEN ANALYSIS OF AEMO DATA

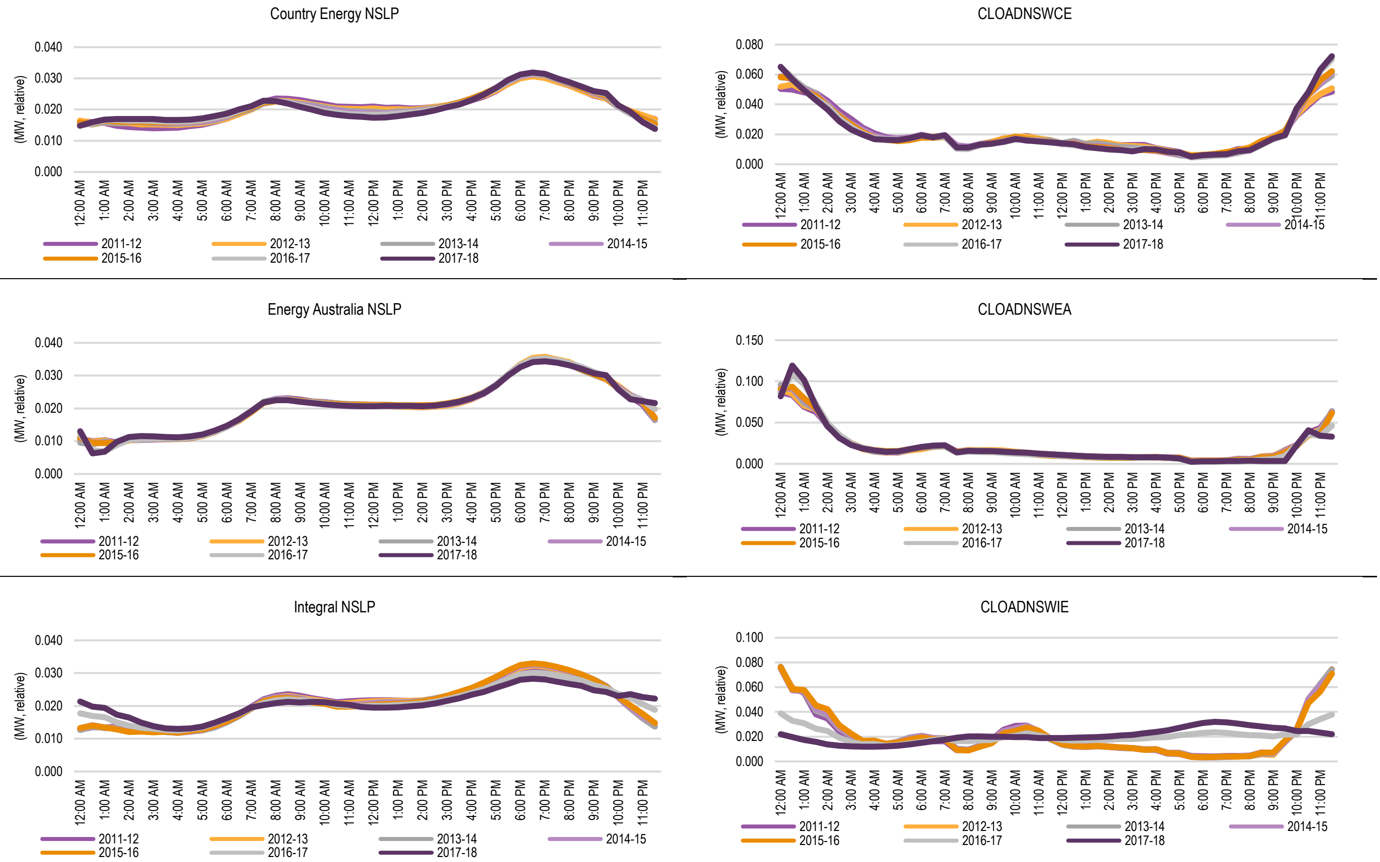
FIGURE 6.2 ACTUAL AVERAGE TIME OF DAY NSLP AND CLP (MW, RELATIVE) – 2011-12 TO 2017-18 – QUEENSLAND



Note: The term relative MW means the loads for each load type and year have been scaled so they sum to one. This removes differences in absolute scale between the different load types 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.

SOURCE: ACIL ALLEN ANALYSIS OF AEMO DATA

FIGURE 6.3 ACTUAL AVERAGE TIME OF DAY NSLP AND CLP (MW, RELATIVE) – 2011-12 TO 2017-18 – NEW SOUTH WALES



Note: The term relative MW means the loads for each load type and year have been scaled so they sum to one. This removes differences in absolute scale between the different load types 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.

SOURCE: ACIL ALLEN ANALYSIS OF AEMO DATA

FIGURE 6.4 ACTUAL AVERAGE TIME OF DAY NSLP AND CLP (MW, RELATIVE) – 2011-12 TO 2017-18 – SOUTH AUSTRALIA

Note: The term relative MW means the loads for each load type and year have been scaled so they sum to one. This removes differences in absolute scale between the different load types 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.

SOURCE: ACIL ALLEN ANALYSIS OF AEMO DATA

For a given determination year, the load profiles need to be grown to a load forecast. It is usual to use the neutral scenario from the latest AEMO demand forecast.

It is also possible to choose a historical year of loads and grow them to the 50 per cent probability of exceedance (P50) neutral scenario peak demand forecast to produce a single forecast of half hourly demands, however, this implicitly assumes perfect foresight on the part of the retailers in terms of demand and price outcomes. This is clearly an unreasonable assumption – uncertainty in demand and price outcomes provide, in part, the incentives for retailers and generators to hedge. Adopting such an assumption would most likely result in an underestimate in spot prices and hedging costs, and hence an underestimate of the WEC. Further, it is unlikely that the actual demand outcomes for a given historical year will be perfectly repeated in future years.

Instead, it is usual practice to use a number of years of historical load data together with the P10, P50 and P90 peak load, and energy forecasts from the AEMO neutral scenario to produce multiple simulated representations of the half hourly load profile for the given determination year using a Monte Carlo analysis. These multiple simulations will include a mix of mild and extreme representations of demand – reflecting different annual weather conditions (such as mild, normal and hot summers).

Described below are the techniques used by ACIL Allen, EY and Frontier to forecast the half-hourly load profiles:

- ACIL Allen:
  - The half-hourly demand profiles of the past four years are obtained. The profiles are adjusted by 'adding' back the estimated rooftop PV generation for the system demand and each NSLP (based on the amount of rooftop PV in each distribution network).
  - A stochastic demand model is used to develop about 50 weather influenced simulations of hourly demand traces for the NSLPs, each regional demand, and each renewable resource[21] – importantly maintaining the correlation between each of these variables. The approach takes the past four years of actual demand data, as well as the past 50 years of weather data and uses a matching algorithm to produce 50 sets of weather-related demand profiles of 17,520 half-hourly loads. This approach does not rely on attempting to develop a statistical relationship between weather outcomes and demand – instead it accepts there is a relationship and uses a matching algorithm to find the closest matching weather outcomes for a given day across the NEM from the past four years to represent a given day in the past.
  - The set of 50 simulations of regional system demands is then grown to the AEMO demand forecast using a non-linear transformation so that the average annual energy across the 50 simulations equals the energy forecast, and the distribution of annual peak loads across the 50 simulations generally matches the distribution of peak loads inferred by the P10, P50 and P90 peaks from the AEMO demand forecast.
  - A relationship between the variation in the NSLPs and the corresponding regional demand from the past four years is developed to measure the change in NSLP as a function of the change in regional demand. This relationship is then applied to produce 50 simulations of weather related NSLP profiles of 17,520 half-hourly loads which are appropriately correlated with system demand, but also exhibit an appropriate level of variation in the NSLP across the 50 simulations.
  - The projected uptake of rooftop PV for the determination years is obtained (either from AEMO or using our internal rooftop PV uptake model).
  - The half-hourly rooftop PV output profile is then grown to the forecast uptake and deducted from the system demand and NSLPs
- EY:
  - EY appears to use the past five years of historical demands and the AEMO P10 and P50 forecasts to produce 10 demand sets. The P10 and P50 forecasts are given a weighting of 30 per cent and 70 per cent respectively. Excluding the P90 demand forecast from the simulations may well result in a narrower distribution of outcomes. All else being equal, this runs the risk of understating the relative volatility in the market since the lower part of the distribution is excluded (a low spot price and demand year could well result in a higher WEC since the retailer could be making substantial difference payments to its hedge counterparties, and recovering the cost from a smaller energy base).
- Frontier:
  - Frontier appears to use a similar approach to ACIL Allen in that it uses the past few years of actual demand data and then generates a large number of simulated demand sets. However, it does not appear to scale the simulated demand sets to the AEMO demand forecast. This may

[21] Described further in section 6.1.5

underrepresent the variability of the annual demand sets in the future if the past few years of actual demands display a low degree of inter-year variability.

We propose that the approach used by ACIL Allen for the QCA be adopted to forecast the half-hourly load profiles.

6.1.5 Forecast the half-hourly renewable energy resource profiles

The recent and continued rapid investment in utility scale renewable energy in the NEM means that intermittent half-hourly renewable energy output is just as much a source of variability in the half-hourly demand-supply balance as demand itself. Therefore, it is important to develop simulations of half-hourly wind and solar farm output traces. It is also important that these are correlated appropriately with regional demand.

Described below are the techniques used by ACIL Allen, EY and Frontier:

- ACIL Allen:
  - The construction of the 50 simulated half-hourly wind farm and solar project output profiles is completed simultaneously with the construction of the half-hourly demand profiles. ACIL Allen has grouped existing and potential wind farm and solar projects into 25 representative profile zones throughout the NEM.
  - For each wind zone we have used the observed output profiles from the existing wind farms and Bureau of Meteorology (BOM) data for the past four years to generate representative profiles which are then scaled to a single MW (to remove the difficulties of dealing with different sized projects). The representative sets of observed profiles are then piggybacked into the demand matching process (as described above) so that if a day of observed demands from the past four years is selected in a simulation set, then the corresponding set of half-hourly wind and solar output profiles is also selected. This approach maintains the correlation between demand, and wind and solar farm output. The simulated resource profiles are scaled to the capacity of each existing and committed renewable energy project within each zone.
- EY:
  - EY appears to take a similar approach, but again only produces five simulated sets. There also appears to be more reliance placed on using BOM data to simulate wind and solar farm output using EY's simulation models, whereas ACIL Allen makes use of actual observable wind and solar farm resource output from the past four years of AEMO data wherever possible.
- Frontier:
  - Frontier do not give any detail on their simulation of utility scale renewable energy resource traces in their report to the ESC as Frontier does not appear to undertake spot price modelling when estimating the WEC.

We propose that the approach used by ACIL Allen for the QCA be adopted to forecast the half-hourly renewable energy resource profiles.

6.1.6 Generate half-hourly thermal power station availability simulations

Thermal power station availability is another source of price volatility in the NEM. Therefore, the spot market modelling needs to account for this. Although half-hourly availability is difficult to predict, historical data makes it relatively straight forward to estimate the distribution and coincidence of power station outages.

Described below are the techniques used by ACIL Allen, EY and Frontier:

- ACIL Allen:
  - Using binomial probability theory ACIL Allen simulates 11 sets of half-hourly forced outages for each thermal generator unit which are defined by an outage rate assumption as well as an outage duration assumption (based on observed historical data). This process allows a range of outage outcomes to be produced for each generator unit. The most important factor in outages is coincidence – if a number of units are forced out at the same time, volatile prices usually result (and vice versa). The process used to simulate the outage sets allows these sorts of coincidences to be represented appropriately.

- EY:
  - EY appears to use the same technique as ACIL Allen – using Monte Carlo simulations to generate five different generator forced outage profiles, based on the forced outage probabilities for each generator, as estimated by AEMO.
- Frontier:
  - No details of Frontier's approach to simulating thermal power station availability is included in their report to the ESC as Frontier does not appear to undertake spot price modelling when estimating the WEC.

We propose that the approach used by ACIL Allen for the QCA be adopted to forecast the half-hourly thermal power station availability simulations.

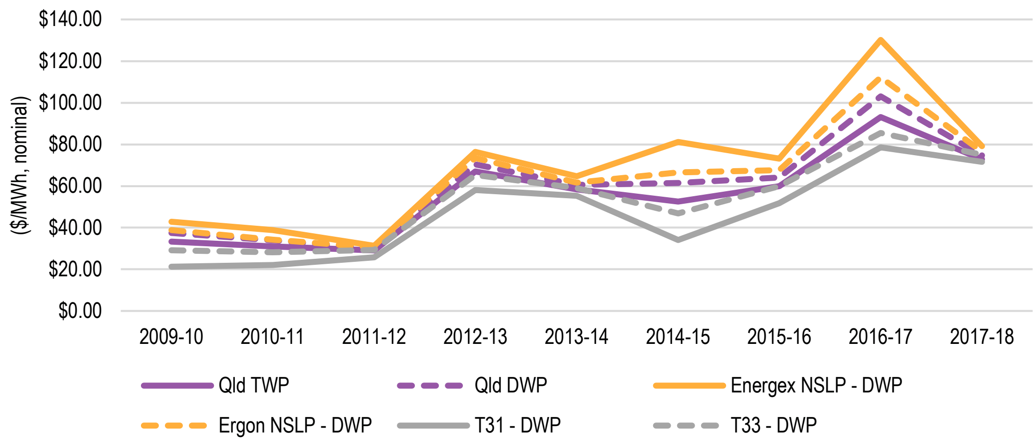
6.1.7 Forecast half-hourly wholesale electricity spot prices

It is usual for the half-hourly spot prices for a given determination year to be modelled by way of simulation – typically using a market simulation model.

Described below are the techniques used by ACIL Allen, EY and Frontier:

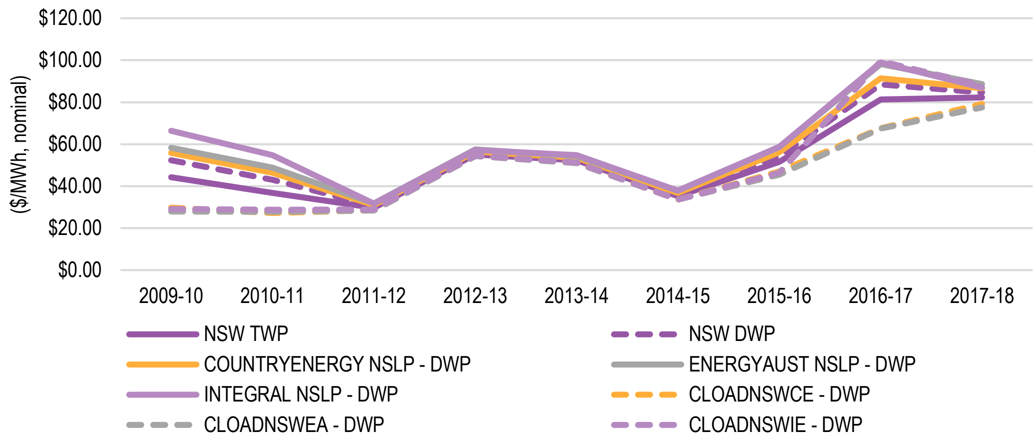
- ACIL Allen:
  - ACIL Allen's proprietary wholesale energy market model, *PowerMark*, is run to estimate the hourly spot prices for the given determination year for about 500 simulations by using the 50 demand simulated demand and renewable energy resource sets and 11 thermal plant outage sets to produce about 500 simulated sets of 8,760 hourly prices.
  - It is possible to run the simulations at the half-hourly resolution level, but our analysis does not suggest any improvement in the richness of the results and therefore does not warrant the doubling in model run time.
- EY:
  - EY appears to use the same approach as ACIL Allen – using their in-house spot market simulation model to produce about 50 simulated set of half hourly spot prices.
- Frontier:
  - Frontier appears to be proposing to the ESC not to undertake spot market modelling and instead use the past couple of years of actual spot price outcomes (together with corresponding demands). The actual spot price outcomes are scaled in some way to match the ASX Energy contract prices. This assumes the historic relationship between customer load and spot price remains largely unchanged for the determination year. This is unlikely to be a reasonable assumption given the continued uptake of rooftop PV, recent commissioning of utility scale PV, and recent changes in thermal power station input costs (coal price and gas price) and availability (such as the closure of Hazelwood). Not only do these changes impact price levels on average, they change the shape of the price profile – resulting in a changing relationship between the NSLPs and price. This is demonstrated clearly in Figure 6.5 to Figure 6.7 which show how the demand weighted spot price for the NSLPs and CLPs has moved differently to the respective regional time weighted and load weighted spot price over the past decade.

FIGURE 6.5 QUEENSLAND TIME WEIGHTED WHOLESALE ELECTRICITY SPOT PRICE VERSUS NSLP AND CLP DEMAND WEIGHTED PRICE (DWP) ($/MWH, NOMINAL)



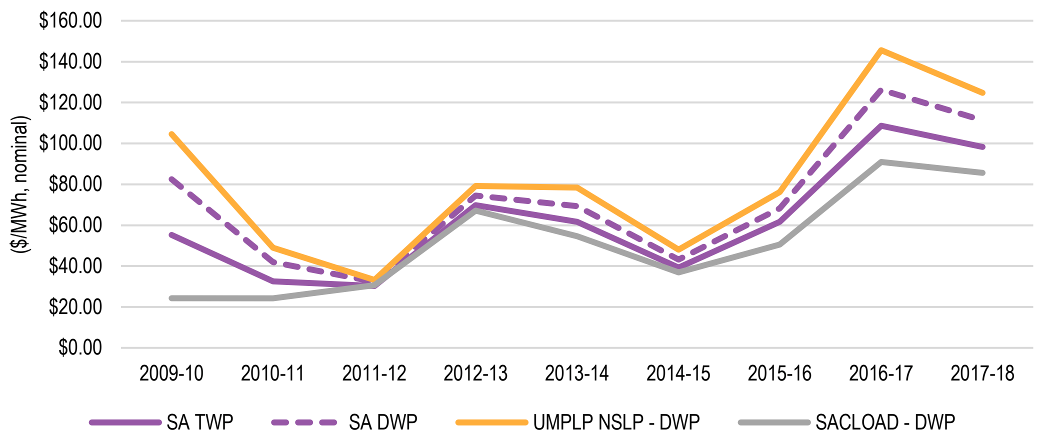
SOURCE: ACIL ALLEN ANALYSIS OF AEMO DATA

FIGURE 6.6 NEW SOUTH WALES TIME WEIGHTED WHOLESALE ELECTRICITY SPOT PRICE VERSUS NSLP AND CLP DEMAND WEIGHTED PRICE (DWP) ($/MWH, NOMINAL)



SOURCE: ACIL ALLEN ANALYSIS OF AEMO DATA

FIGURE 6.7 SOUTH AUSTRALIA TIME WEIGHTED WHOLESALE ELECTRICITY SPOT PRICE VERSUS ENERGEX NSLP DEMAND WEIGHTED PRICE (DWP) ($/MWH, NOMINAL)



SOURCE: ACIL ALLEN ANALYSIS OF AEMO DATA

We propose that the approach used by ACIL Allen for the QCA, or by EY for the AEMC, be adopted to forecast the wholesale electricity spot prices, although we would recommend a larger number of simulations to those developed by EY to maximise the chances of properly capturing the extend of variability in outcomes. Further, our experience is that running the simulations at the half-hourly resolution level does not provide any additional richness in information when considering the additional effort, model run time, and analysis time required.

6.1.8 Estimate forward contract prices

Contract prices are used in the hedge model together with the contracting strategy, load, and spot prices, to calculate the annual cost of procuring hedges as well as the hourly difference payments.

ACIL Allen proposes to use ASX Energy data, together with broker data. Figure 6.8 compares the annual trade volumes of quarterly base, peak and cap contracts for the three regions. The volumes are cumulative from the first trade up to, and inclusive of, 10 April 2019 (the data closure date used in the 2019-20 final determination for the QCA). It can be seen that the volume of trades in New South Wales is very similar to Queensland.

The volume of trades in South Australia is very small, and in the case of peak contracts, non-existent for some quarters. This means that broker data would be relied upon to fill in the gaps for South Australia. ACIL Allen has contacted brokers and can confirm that there is OTC trade data for South Australian peak contracts. Broadly, the volume of OTC trades in South Australia is about 10 per cent of the volume of trades in Queensland and New South Wales.

FIGURE 6.8 ANNUAL TRADE VOLUMES OF QUARTERLY ASX ENERGY BASE, PEAK AND CAP PRODUCTS FOR 2019-20 – UP TO TIME OF 2019-20 FINAL DETERMINATION FOR QCA

SOURCE: ACIL ALLEN ANALYSIS OF ASX ENERGY DATA

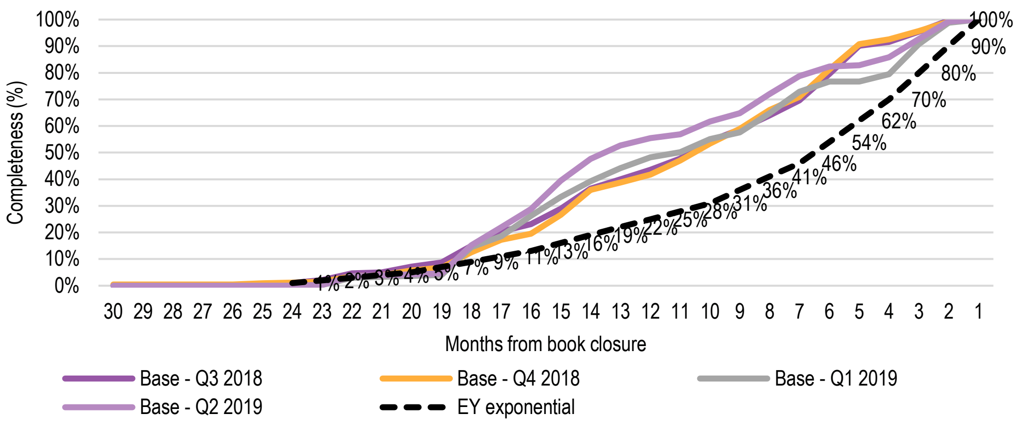
Described below are the techniques used by ACIL Allen, EY and Frontier to estimate contract prices:

— ACIL Allen:
  - ACIL Allen analyses ASX Energy contract data to estimate contract prices, which is verified with broker data. It is assumed the hedge book consists of a portfolio of base, peak and cap quarterly contracts – hence prices for these products need to be derived.
  - We assume a book build based on the observed trade volumes and the price estimate is equal to the trade volume weighted average price. We do not place a time limit on the book build – it essentially starts when the first observable trade is made in the ASX Energy data.
  - The same approach and data are used for small and large retailers.

— EY:
  - EY uses a 12-month and a 2-year build-up of hedges for small and large retailers respectively.
  - Rather than using the observable trade volumes as the weights to calculate the weighted average cost of each product, EY uses an exponential build-up of the portfolio. Although this is not unreasonable, we note that the trend in cumulative trades on ASX Energy is rarely an exact exponential shape as demonstrated in Figure 6.9.

— Frontier:
  - Although Frontier normally prefers to use the most recent '40 day period' of trades and prices to calculate the trade volume weighted average price as a proxy for the current market value of contracts, they are using a 12 month trade volume weighted average in the current Victorian Default Offer (VDO) work for the ESC.
  - Our view is that using all available data provides less volatile estimates of the contract prices over time.

FIGURE 6.9 HEDGE BOOK BUILD UP – USING ASX ENERGY VOLUMES – QUEENSLAND QUARTERLY BASE CONTRACTS



SOURCE: ACIL ALLEN ANALYSIS OF ASX ENERGY DATA

We propose that the approach used by ACIL Allen for the QCA be adopted to estimate contract prices.

6.1.9 Develop contracting strategy

The contracting strategy adopted in the estimation process is intended to represent a strategy that a prudent and efficient retailer would undertake to hedge against risk in the spot price in a given year.

Described below are the techniques used by ACIL Allen, EY and Frontier:

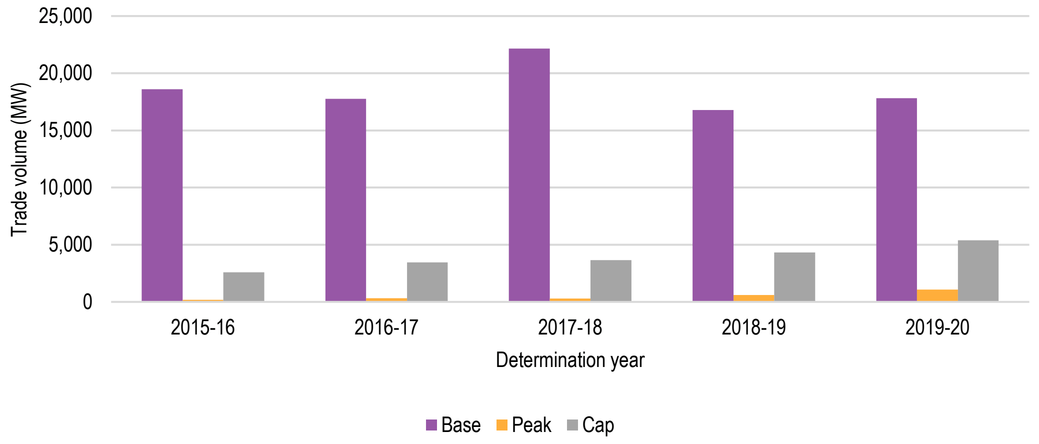
- ACIL Allen:
  - The contract volumes adopted for the QCA attempt to find a pragmatic balance between pure economic theory and commercial reality. Our approach assumes a retailer will seek a strategy that minimises the variability in the WEC, and does not just minimise the WEC. It could be the case that a strategy happens to minimise the cost, but leaves the retailer exposed to a high degree of residual spot price risk.
  - In our work for the QCA, the hedging strategy is not necessarily varied for every determination year – it tends to change when there is a sufficient change in either the shape of the load profile (for example, due to the continued uptake of rooftop PV) or a change in the relationship between contract prices for the different contract products (for example, in some years base contract price increase much more than peak contract prices which can influence the strategy).
  - Although we test multiple hedging strategies by varying the mix of base/peak/cap contracts for each quarter – we test a discrete number of strategies only. We express the strategies in terms of percentiles of load and we define the strategies in 10 percentile increments for base and peak contracts, and 5 percentile increments for cap contracts. The strategy is further simplified in that the same percentiles are used in each quarter. The point of this approach is to not over-engineer the strategy selection process and thereby introduce a false sense of precision.
  - Over the past eight or so years, the hedging strategy for our work for the QCA has changed three times. This is not surprising when the trade volumes of the different products on ASX Energy have not changed dramatically as shown in Figure 6.10.
  - The hedging strategy that results in the lowest 95th percentile WEC (from the 500 or so simulated WECs) is adopted – thereby reducing the residual spot price risk.
  - For the 2019-20 determination for the QCA (in which there were 48 simulated demand sets), the quarterly contract volumes for the NSLPs were calculated as follows:
    - The base contract volume was set to equal the 70th percentile of the off-peak period hourly demands across all 48 demand sets for the quarter.
    - The peak period contract volume was set to equal the 80th percentile of the peak period hourly demands across all 48 demand sets minus the base contract volumes for the quarter.

- The cap contract volume was set at 105 per cent of the median of the annual peak demands across the 48 demand sets minus the base and peak contract volumes.

– In other words, the same hourly hedge volumes (in MW terms) are applied to each of the 48 demand sets for a given settlement class and quarter, and hence to each of the 500 or so simulations. To be clear, we do not alter the hedge volume (in MW terms) on an ex-post basis for each of the 48 simulated demand sets. Therefore, the approach we used resulted in a hedging strategy that did not rely on perfect foresight but relied on an expectation of the distribution of hourly demands across a range of temperature outcomes.

– Once established, these contract volumes were then fixed across all 500 or so simulations within the hedge model when calculating the WEC.

FIGURE 6.10 ANNUAL TRADE VOLUMES OF QUARTERLY ASX ENERGY BASE, PEAK AND CAP PRODUCTS - QUEENSLAND



Note: Volumes taken at the point of the data cut-off date for the respective final determination.

SOURCE: ACIL ALLEN ANALYSIS OF ASX ENERGY

— EY:

– In its report to the AEMC for the residential retail price trends review, EY states *that the objective of the retail portfolio optimisation was to determine a level of hedging that provides a consistent weekly electricity cost, based on the calculated contract strike prices, and the forecast demand, regardless of the volatility of the wholesale market price. A gradient descent algorithm was employed to optimise each portfolio*[22].

— Frontier:

– In its report to the ESC and ICRC, Frontier notes *it determines hedging costs based on the Minimum Variance Portfolio (MVP) approach, which determines the efficient combinations of hedging products to meet a particular load profile given a particular set of spot prices, and the cost of each of these efficient combinations of hedging products. The result is an efficient risk/reward frontier. This frontier reflects the many possible efficient hedging strategies, where an efficient hedging strategy is defined as a strategy that provides the lowest cost for a given level of risk (or, to put that another way, provides the lowest risk for a given cost)*[23].

The three approaches are generally similar conceptually – in simple terms, they seek to minimise the variability in the WEC.

We propose that the approach used by ACIL Allen for the QCA be adopted to estimate the contract strategy.

[22] https://www.aemc.gov.au/sites/default/files/2018-12/EY%20-%202018%20Residential%20Electricity%20Price%20Trends%20-%20Wholesale%20Market%20Cost%20Modelling%20-%20CLEAN.pdf, p.16.

[23] https://www.icrc.act.gov.au/__data/assets/pdf_file/0010/1349605/Report-1-of-2019-Technical-Paper-Electricity-Model-and-Methodology-Review-201819.pdf , p.8.

6.1.10 Calculate spot and contracting cost for each half hour and aggregate

After completing the above steps, the hedge model is then run for each of the simulations to estimate a WEC per simulation. For a given half hour of a given simulation the cost is equal to the sum of the spot purchase cost, contract purchase costs, and difference payments. For a given simulation, this results in 8,760 hourly or 17,520 half-hourly costs which are summed and divided by the energy requirements for the given simulation to give an annual WEC in $/MWh terms.

Described below are the techniques used by ACIL Allen, EY and Frontier:

- ACIL Allen:
  - ACIL Allen takes the 500 or so simulated WECs derived from the hedge model and finds the 95th percentile of these values which is used as the final value of the WEC.
  - We use the 95th percentile value rather than the median and average of the 500 or so WECs to minimise the risk of understating the actual wholesale energy costs incurred by a retailer.
  - Using the 95th percentile allows for the residual risk associated with a one in 20-year outcome to be incorporated into the wholesale energy cost estimate, which we think is appropriate.
- EY:
  - EY appears to take a weighted average of the 50 simulated WECs.
- Frontier:
  - In its work for the ESC on the VDO, Frontier takes the WEC from the median simulated year as the final estimate of the WEC. The median simulated year is determined by ranking the years based on the simulated annual load weighted spot price and finding the mid-point.

Although taking the average or median WEC from the simulations is valid, it increases the risk of understating the actual wholesale energy cost incurred by a retailer, therefore, we propose that the approach used by ACIL Allen for the QCA be adopted to estimate the final WEC.

6.2 Environmental costs

ACIL Allen proposes the market-based approach to estimating environmental costs.

The key steps to estimating environmental costs are:

- for the LRET:
  - use CER published RPP value and mandated targets in conjunction with a projection of liable acquisitions
  - acquire broker data for LGC forward prices and use this data to calculate the average LGC price based on a reasonable lead time over which an efficient retailer is likely to obtain LGCs
  - for each compliance (calendar) year in the DMO period, multiply the calendar year RPP estimate by the calendar year average LGC price
  - the cost of complying with the LRET in the DMO financial year period is found by averaging the calendar estimates
- for the SRES:
  - use CER published binding and non-binding STP values
  - utilise the CER STC clearing price
  - for each compliance (calendar) year in the DMO period, multiply the calendar year STP estimate by the calendar year STC clearing price
  - the cost of complying with the SRES in the DMO financial year period is found by averaging the calendar estimates
- for the ESS:
  - use IPART published ESS targets
  - acquire broker data for ESC forward prices and use this data to calculate the average ESC price based on a reasonable lead time over which an efficient retailer is likely to obtain ESCs
  - for each compliance (calendar) year in the DMO period, multiply the calendar year ESS target by the calendar year average ESC price
  - the cost of complying with the ESS in the DMO financial year period is found by averaging the calendar estimates

- for the REES:
  - use the estimates of the cost of REES in $/MWh provided in the 2018 AEMC price trends report and hold constant in nominal terms.

6.3 Other costs

ACIL Allen proposes to use publicly available information to estimate other costs.

The key steps to estimating other costs are:

- for market fees:
  - use AEMO's latest budget report which provides current and projected fees by financial year
- for ancillary services costs:
  - use AEMO published weekly ancillary service recovery data and average the most recent 52 weeks of costs to recover ancillary services from customers
- for prudential costs, use:
- the sum of AEMO and hedge prudential costs
  - for AEMO prudential costs
    - AEMO volatility factors
    - ACIL Allen's spot price projections (also used to estimate the WEC)
    - assumed cost of funding a bank guarantee (in % p.a.)
    - apply AEMO volatility factors to ACIL Allen's spot price projections and divide by 42 rolling days to find the maximum credit limit (MCL) applicable to each MWh of retailer purchases
    - multiply the MCL in $/MWh by the bank guarantee funding cost for 42 days to find the AEMO prudential cost in $/MWh
  - for hedge prudential costs
    - ASX Energy initial margin parameter
    - Weighted-average ASX Energy futures contract prices (also used to estimate the WEC)
    - net funding cost, equal to an assumed WACC adjusted for an assumed return on cash lodged with the clearing
    - apply the ASX Energy margin parameters to the weighted-average quarterly ASX Energy futures prices and then divide by the average hours in a quarter to find the initial margin in $/MWh for each quarter
    - apply the net funding cost to the initial margin to find the prudential cost in $/MWh
    - weight the prudential cost by the proportion of contracts hedged against average annual energy within a network area and then sum the estimates to find the total hedge prudential cost in $/MWh for a network area

Reliability and Emergency Reserve Trader (RERT)

Given the RERT is called upon under extreme circumstances only, ACIL Allen is of the opinion that it is difficult to project into the future. Although it may be possible to make use of previous costs of the RERT and relate these to AEMO's projection of USE in the ESOO, there is little data available at this point to take this approach.

Therefore, as with the ancillary services, we propose to take the RERT costs as published by AEMO for the 12-month period prior to the determination year. We note that the ESC uses this approach in the VDO. However, the ESC expresses the RERT cost on a per customer basis. ACIL Allen proposes to express the cost based on energy consumption. This would require taking the reported cost in dollar terms from AEMO for the given region and prorating the cost across all consumers in the region on a consumption basis.

ACIL ALLEN CONSULTING PTY LTD
ABN 68 102 652 148

ACILALLEN.COM.AU

ABOUT ACIL ALLEN CONSULTING

ACIL ALLEN CONSULTING IS THE LARGEST INDEPENDENT, AUSTRALIAN OWNED ECONOMIC AND PUBLIC POLICY CONSULTANCY.

WE SPECIALISE IN THE USE OF APPLIED ECONOMICS AND ECONOMETRICS WITH EMPHASIS ON THE ANALYSIS, DEVELOPMENT AND EVALUATION OF POLICY, STRATEGY AND PROGRAMS.

OUR REPUTATION FOR QUALITY RESEARCH, CREDIBLE ANALYSIS AND INNOVATIVE ADVICE HAS BEEN DEVELOPED OVER A PERIOD OF MORE THAN THIRTY YEARS.