Draft methodology for estimating energy purchase costs

Draft methodology for estimating the energy purchase costs for each retail electricity tariff for Queensland in 2012/13

November 2011

ACIL Tasman

Economics Policy Strategy

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1 Introduction

ACIL Tasman has been engaged by The Queensland Competition Authority (the Authority) to undertake estimation of the energy purchase costs associated with each retail tariff to potentially apply in the 2012/13. This report sets out the methodology proposed by ACIL Tasman to undertake these estimates.

On 11 May 2011, the Queensland Competition Authority received a Ministerial Direction to investigate and report on:

- an alternative retail electricity pricing methodology for the determination of the cost components under an N (network) + R (retail and energy purchase costs) approach
- a revised set of retail electricity tariffs aligning with the network tariffs, which could be applied from 1 July 2012.

In response to the Ministerial Direction the Authority released an Issues Paper in June 2011 and received submissions from key stakeholders. In considering an appropriate methodology for estimating EPC this Issues Paper and the associated responses have been considered.

While not included in the Ministerial Direction, in the letter accompanying the Ministerial Direction the Minister stated that the Queensland Government is concerned about the pressure that rising electricity prices were placing on household budgets and wanted to ensure that the Authority is aware of this issue for Queensland consumers. However, this statement has no bearing on ACIL Tasman's proposed methodology for estimating an EPC which is intended to estimate as accurately as possible the EPC, by tariff, faced by a representative retailer operating in the NEM in Queensland.

Following on from the Ministerial Direction, on 22 September 2011 the Authority received a Ministerial Delegation under Section 90AA(1) of the Electricity Act 1994 to determine regulated retail electricity tariffs for Queensland to apply in 2012/13.

Under the Delegation's Terms of Reference (TOR) the Authority is to ensure that the revised retail electricity tariffs are:

- cost-reflective
- consistent with the Government's policy objective that consumers, wherever possible, have the opportunity to benefit from competition and efficiency in the marketplace
- available to customers in the Energex supply area using less than 100MWh per year

- available for all customers in the Ergon Energy supply area under the Queensland government's Uniform Tariff Policy
- to exclude declining block tariffs and incorporate inclining block tariffs for residential customers
- to incorporate a new voluntary time-of-use tariff for residential customers.

The TOR also specified that calculation of the energy cost component of each tariff, which is the subject of this report, must consider:

- the cost of energy
- market fees and ancillary services costs
- energy losses as published by the Australian Energy Market Operator (AEMO)
- the impact of carbon pricing
- costs associated with complying with Commonwealth and State environmental and energy efficiency schemes
- any other costs imposed on retailers by any new compulsory scheme.

The methodology discussed in this report is consistent with the TOR and is focussed on the estimation of the energy purchase costs (EPC) for each tariff. These costs include the wholesale energy purchases, the costs of compliance with the Commonwealth Government renewable energy schemes, the costs of carbon pricing, the cost of compliance with the Queensland gas scheme and the cost of National Electricity Market (NEM) fees and ancillary services. The EPC does not include the cost of the Queensland Solar Bonus as this cost is met by Energex and Ergon Energy and included in the network costs.

The network and retailing costs, which are also included in the retail tariffs, are handled separately from the EPC calculation and are not covered in this methodology paper.

2 Outline of approach

The EPC includes:

- wholesale energy purchase costs (including allowance for transmission and distribution losses and the cost of carbon pricing)
- costs of complying with the Commonwealth Government's Large-scale Renewable Energy Target (LRET) and Small-scale Renewable Energy Scheme (SRES)
- cost of complying with the Queensland Government's Gas Electricity Certificates (GEC) scheme
- cost of National Electricity Market (NEM)market fees and ancillary service payments.

In arriving at an appropriate methodology for estimating the EPC, ACIL Tasman has been guided by the TOR in the Ministerial Delegation which contains the following statements:

- Queensland electricity consumers should, wherever possible, have the opportunity to benefit from competition and efficiency in the market place.
- For retail electricity markets to be successful electricity prices must reflect the cost of supply.

The Ministerial Delegation specifies that in general tariffs should be cost-reflective.

These statements have been used to guide the selection of an appropriate methodology for estimating the wholesale energy purchase costs for a representative retailer and for each of the individual retail tariffs.

To meet the Delegation's TOR requirement for the tariffs to provide consumers with the benefits of competition it is important that the energy cost estimates are not set at a level which excludes retail competition and potentially damages the incumbent retailer. The two market based methodologies outlined in this report are aimed at estimating the costs as near as possible to the actual outcome but, given the data limitations and the complexity and multitude of approaches available to a retailer in undertaking energy purchases, all are subject to a degree of uncertainty.

The greatest risk to competition and the incumbent retailer is if the EPC is underestimated. However, the need to ensure costs are not underestimated needs to be balanced against the requirement that prices are cost reflective. Assumptions such as the load forecast and contract cover used in the pool price modelling will need to be considered in this context.

2.1 Data sources

The EPC analysis is based on the costs faced by a representative retailer operating in the Energex area as proposed by the Authority on the basis that the retail tariffs are to be cost reflective for customers in the Energex network area. The same tariffs will apply to customers in the Ergon Energy network area but will be supported by a Community Service Obligation (CSO) from the Queensland Government under its Uniform Tariff Policy.

ACIL Tasman will access a variety of data sources to estimate the EPC of the individual tariffs and overall for a representative retailer operating in the Energex area.

The data sources include:

- Half hour load traces for each NEM region published by the Australian Energy Market Operator (AEMO)on its website to be used in the pool price modelling
- Half hour load traces for each Transmission Node Identities (TNI) for Energex area from AEMO via the Authority to provide an overall load trace for Energex
- Controlled load traces from the AEMO website for use in estimating the cost of supplying these tariffs
- Interval meter data for Energex area customers to establish load traces for the various commercial and industrial tariffs
- 400 domestic customer interval meter recordings from Energex to estimate a residential load trace
- Net System Load Profile (NSLP) for Energex from the AEMO website to be used for estimation of load traces for tariff groups without interval metres
- Customer usage profiles for each tariff from Energex to be used to uplift the various load traces to represent the full load in each tariff
- Energex forecasts of system summer and winter peaks and annual energy submitted to the AER to be used in estimation of the Energex overall load trace for 2012/13
- Load forecast of summer and winter peak demands and annual energy for each NEM region published by AEMO in its Electricity Statement of Opportunities (ESOO) to be used as a basis for estimating the load trace for 2012/13
- Future electricity swap and cap contract data from d-cypha Trade for use in establishing contract prices used in estimating wholesale energy costs. This data would not be required if the stochastic approach is chosen as the preferred methodology.

- Large-scale Generation Certificate (LGC) prices from AFMA used in estimating the cost of complying with the LRET
- Market prices for traded Small-scale Technology Certificates (STC) from AFMA for possible use in estimating the cost of complying with SRES
- Small-scale Technology percentage (STP) from the Office of the Renewable Energy Regulator (ORER) for use in estimating the cost of complying with SRES
- Future prices for QGCs from AFMA for possible use in estimating the cost of complying with the Queensland gas scheme
- Existing and new entrant generator characteristics and cost data from AEMO and internal modelling and analysis for use in pool price modelling
- NEM data on market fees and ancillary services costs from the AEMO website for use in estimating the market fees and ancillary service charges
- 41 years of three hourly temperature data for capital cities to be used for estimating the weather corrected or 50% probability of exceedence (POE) load traces used in the pool price modelling and stochastic analysis.

The data sets outlined will be available for the analysis although not all will be used in the calculation of the EPC, depending on the adopted methodology.

2.2 Representative retailer

The Authority has proposed a definition of the representative retailer and has asked ACIL Tasman to adopt that definition for the purposes of developing its draft methodology.

The Authority proposes to define the representative retailer as a retailer that:

a) is an incumbent retailer of sufficient size to have achieved economies of scale

b) serves small and large retail customers in SE Queensland and other jurisdictions across the NEM

c) retails electricity on a standalone basis

d) is not vertically integrated with an electricity generator.

In assessing the EPC for each tariff which would be faced by a representative retailer operating in the Energex network area ACIL Tasman has assumed that its methodology should ensure the total of the estimated energy purchase costs for the individual tariffs will not exceed the aggregate energy purchase costs of the representative retailer. This means that methodology will need to ensure that the estimates of the cost of supplying the individual tariffs based on their individual load shape is consistent with the overall energy purchase cost of such a retailer.

2.3 Wholesale energy purchase costs

There are a number of approaches which could be used to estimate the wholesale energy purchase costs in Queensland and these include:

Approach 1: long-run marginal cost of supply (LRMC) of supply

Approach 2: pool price projection overlayed by contract prices and a contracting strategy

Approach 3: mean of the distribution of annual price projections under a wide variety of possible weather and plant outage outcomes

Approach 4: combinations of the above methods.

The methodology used in Queensland in recent years for calculation of changes in wholesale energy purchase costs for input to the calculation of the BRCI involved Approach 4, whereby a simple average of Approaches 1 and 2 was used.

The estimate of energy purchase costs will account for transmission and distribution losses.

The merits of each of the methods are discussed in detail in Section 3. However the assessment of the appropriate approach to estimating wholesale energy purchase costs will take into account:

- whether or not the methodology meets the conditions of the Ministerial Delegation
- the need to have cost reflectivity at the individual tariff level
- data availability
- transparency
- repeatability of the process
- likely accuracy of the resultant estimates
- feedback from stakeholders.

Furthermore, regardless of the chosen approach, an estimate of the cost of supplying each tariff is required. ACIL Tasman envisages that this will be best achieved by estimating the cost of supplying the individual tariff load traces. In effect, each tariff will have a different load shape and thus have different associated wholesale energy costs. The pool price modelling across the NEM will provide the half-hourly prices which can then be applied to each tariff load to establish the market cost of supplying it.

2.3.1 Incorporation of carbon pricing

The Commonwealth Government is to introduce carbon pricing from 1 July 2012 which will apply to electricity generators and coal and gas producers at a rate of \$23.00 per tonne of CO_2-e emitted. This will add to the wholesale cost of electricity. ACIL Tasman proposes to incorporate an allowance for carbon pricing in its pool price modelling so the resultant electricity prices will include a carbon pricing allowance. The allowance will be in the form of increased generation costs through a carbon price applying to combustion emissions and the increased fuel prices through fugitive emissions from fuel production.

However, we will need to be in a position to quickly rework the estimates of wholesale energy purchase costs without carbon tax if the scheme is not successfully implemented for some reason before the final report is submitted. This will be achieved by undertaking the calculation with and without the effects of carbon pricing. The with and without carbon pricing results will also allow estimation of the effects of the carbon price on retail electricity tariffs.

2.4 Commonwealth renewable energy schemes

2.4.1 LRET

The cost of the LRET scheme is found by applying the Renewable Power Percentage (RPP) to the LGC price to establish the cost per MWh supplied to customers. Spreading the cost to the various tariffs is a relatively simple matter as the cost will be expressed as a cost per MWh. Discussion of the approach to estimating the LGC price for the 2012/13 tariff year is included in more in detail in Section 4.1

2.4.2 SRES

The cost of SRES is found by applying the Small-scale Technology Percentage (STP) to the STC price to estimate the cost per MWh to apply to each tariff. The approach to be followed in estimating the STP and STC is discussed in more detail in Section 4.2

2.5 Queensland Gas Scheme (QGS)

It is still uncertain whether the QGS will be continued when carbon pricing commences. If the QGS is discontinued then, assuming the Government provides adequate compensation to participants, the allowance for the QGS in the retail tariffs will no longer be required. Therefore the methodology outlined in this methodology report would apply only if the QGS continues after carbon pricing. Should the Government simply abandon the scheme without compensating participants then ACIL Tasman assumes that it would be inappropriate to recover any hangover costs in the energy cost component of retail tariffs. The basis might be that gas plant will gain a competitive advantage in the market through the carbon pricing regime which would offset any benefits of the QGS.

The cost of the QGS is found by applying the prescribed percentage (currently 15%) to the GEC price to establish the cost per MWh supplied to customers. However, the scheme is currently oversupplied and there is very limited trading in GECs. This poses a problem for estimating the cost of GECs (discussed further in Section 4.3).

2.6 Market fees and ancillary services

These costs are estimated from information provided on the AEMO website. ACIL Tasman proposes using the same approach as used for the BRCI. This is discussed in more detail in Section 4.4.

3 Wholesale Energy Purchase Costs

Approach 1:	long-run marginal cost (LRMC) of supply
Approach 2:	pool price projection overlayed by a contract price and contracting strategy
Approach 3:	mean of the distribution of projected annual prices under a wide variety of possible weather and plant outage outcomes
Approach 4:	combinations of the above methods.

3.1 Approach 1- LRMC

The use of LRMC as an estimate of wholesale energy supply cost is favoured by most retailers, at least as a floor price, because it was argued that it provides incentive for construction of new plant, it reflects the costs to retailers which own plant, it is more transparent and it avoids the need to rely entirely on contract price and hedging assumptions and pool price modelling.

This support for the LRMC approach ran counter to the Authority's Issues Paper which stated:

> The Authority was of the view that the desire for a competitive electricity market and the need to reflect retailers' actual cost of supplying electricity provided sufficient reasons to move away from the cost-based LRMC,....

ACIL Tasman has considered both the Authority's and retailer's views and on balance generally supports the Authority's views for the following reasons.

The LRMC calculation is an estimate of the full cost of supplying an additional unit of energy in the Queensland market in the tariff year, which in this case is 2012/13. In the form that has been applied in recent calculations of the BRCI (the so-called "greenfields approach") the electricity supply curve and the marginal cost of an additional unit of electricity may bear no resemblance to the cost of supplying an additional unit of energy in Queensland or the NEM in the tariff year. The approach looks forward, attempting to estimate the cost of generating additional units of energy in the future from new entrant plant, ignoring the likely market conditions prevailing at that future time. This approach is *not* attempting an estimate of the retailer's costs in purchasing wholesale energy and, even if the underlying assumptions turn out to be accurate, it is only by chance that it would come close to those costs.

Market conditions can have a major effect on the costs of purchasing energy, such conditions include:

- The effects that major weather events can have on the wholesale price of electricity. For example, the eastern Australian drought which finished in about 2009 brought about a significant increase in the wholesale price of electricity, and electricity contract futures, which should be reflected in the calculation of regulated electricity prices.

- The markets for primary energy inputs for electricity generation, such as coal and gas, have a major effect on wholesale electricity prices. The fuel supply and prices, particularly in the short term as is the case with the 2012/13 tariff year, are largely governed by existing contracts which in the existing strong market conditions generally have lower prices than those available to new entrants in the period under study. World coal prices for example can affect domestic prices significantly and short term changes in the domestic gas market will also affect prices into new entrant power stations. Such conditions will affect the price of wholesale electricity, sometimes significantly, but an LRMC approach, especially the "greenfields approach" can fail to recognize these impacts.
- The market based approach attempts to simulate the impact of such market conditions on wholesale prices passing through price signals to both retailers and consumers. The LRMC approach is likely to miss any price signals arising from over or under supply of generation capacity.
- The market pricing approach includes an assumed contracting strategy that a prudent retailer would use in managing their 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 LRMC excludes the effects of contracting on the retailers' costs.

Furthermore, retailers have suggested that the LRMC be based on greenfield developments to meet the regulated retail load profile alone, as if it is the only load that generators need to meet. This ignores the fact that the market is much larger than the retail load and that other industrial, commercial and non regulated loads tend to make demand less volatile, increasing the availability of reserve on the system and reducing the need to introduce more expensive fast-start generation. Applying an LRMC calculation to the retail load alone ignores the existence of the NEM and the major impact it has had on the wholesale price of electricity.

While these considerations lead us away from the use of an LRMC calculation and towards a market based calculation of EPC, we are not suggesting that a market based calculation is without its difficulties.

3.2 Approach 2 - Market based approach

A market-based methodology would involve estimating the wholesale energy purchase costs that a representative retailer would incur in supplying the wholesale energy under each retail tariff in the Energex network area. The market based calculation that has been used in the calculation of the BRCI to date includes the following steps:

1. Develop a load trace for the year to be projected using the load trace of the most recent year and transforming it to match the AEMO annual energy and 10%, 50% and 90% (POE) peak demand forecasts. These three half-hourly load traces would be used in three different projections of annual half-hourly prices.
2. Carry out a projection of half-hourly prices using a market simulation model for each of the three load traces.
3. Estimate forward contract prices for swaps and caps using forward contract price data such as d-cypha trade
4. Determine an appropriate hedging strategy for a prudent representative retailer and calculate contract volumes
5. Develop a contracting model based on the purchase of contracts with set periods and set mixtures of two-way and one-way hedges and flat and peak contracts. Where available published sources are used for contract strike prices.
6. Bring together the contract prices and volumes with the projected half-hourly pool prices for the three load traces and calculate a cost of energy for the year.

In common with the LRMC calculation, the market price calculation relied on a number of input assumptions concerning price projections for primary energy sources, load growth and load traces. There are other difficulties inherent in this approach:

- It relies on a proprietary market simulation model, a "black box", into which assumptions concerning generation capacity, load growth, outages and generator bidding behaviour are brought together using a replica of the AEMO market settlement algorithm to produce half-hourly regional reference prices (RRPs).
- In the past the approach has used public sources of data such as d-cypha Trade for information on the prices of contracts available to retailers. These prices are used in an assumed contracting strategy along with half-hourly prices produced by the market simulation model to produce a half-hourly wholesale energy cost. The difficulty here is that this approach does not take into account bilateral contracts for difference (CFDs) between generators and retailers. These contracts can form a high proportion of the retailers' contracts and may contain quite different price, volume and term conditions to the over the counter contracts presented in public sources.

The reliance on a proprietary market simulation model to estimate future pool prices presents two problems in the calculation of a regulated price. The first is the "black box" nature of such models. They contain many implicit assumptions about the way the market operates, including how both thermal and hydro generators formulate their offers, the frequency and duration of random generator outages and the ways in which transmission constraints are dealt with. These model features have usually been developed over time on the basis of the modelers' research and experience and they are not easy for an outsider to verify.

This leads to the second problem associated with using proprietary market models; consistency. It would be undesirable for a change in the market model used, all other inputs remaining the same, to bring about a change in the calculated wholesale energy price.

This has been handled in the past (when the consultants assisting QCA in the calculation of the BRCI have changed) by ensuring that the data sources and the processing of input data remain transparent and consistent and that any difference in model answers can be isolated as a model effect. This has been done by applying the new model to the previous year’s data (ensuring all inputs are identical) and identifying any difference in results. This difference can be applied as a model effect and results for the new projection adjusted accordingly.

The estimation of contract market prices for 2012/13 poses a significant problem at present as there has been virtually no trading in 2013 contract futures because of the uncertainty over whether or not the Commonwealth Government’s proposed carbon pricing regime will be successfully implemented. This means that there are no reliable contract prices for the latter half of the 2012/13 financial year, ruling out this approach at least until market liquidity is established for 2013, which will probably not begin to occur until the future of the carbon tax is known with more certainty. Even if the contract market reaches an acceptable level of liquidity before the final decision is due, it is unlikely to provide a reliable guide to the average contract prices in 2013 because of the shortened timeframe for the price formation.

A further weakness of this approach is the need to determine an appropriate retailer hedging strategy and providing estimates of forward contract prices. While some contracts are bought in over the counter trades at transparent market prices a high proportion of retailer hedges are bought through bilateral negotiations with generators. In these cases the prices and other terms are not known.

It is also difficult to determine a contracting strategy that is representative of a prudent retailer. If a highly risk averse approach is followed then the projection of the cost of energy is likely to be noticeably higher than that faced by a prudent retailer. On the other hand a less risk averse approach could well deliver costs which are lower than faced by a prudent retailer. Arriving at a hedging strategy which represents an appropriate approach in the current circumstances presents significant difficulties.

The lack of reliable contract price data, particularly for 2013, means that this methodology is not viable for the 2012/13 year. However, in future when the uncertainty over carbon pricing is removed and contract prices are more representative of actual costs faced by a retailer then this approach should be reconsidered as representing a preferred method.

3.3 Approach 3 - Annual price distribution

3.3.1 Background

Given the difficulties and shortcomings of Approaches 1 and 2 ACIL Tasman proposes a market based approach which involves establishing a distribution of possible load weighted annual prices for 2012/13 for each tariff and the overall Energex load incorporating weather and plant outage variations.

The reason retailers wish to take out forward contracts covering their load is so that they are insured against the potentially high prices that can sometimes occur in the NEM. The distribution of possible price outcomes is not a symmetrical and well-behaved bell curve where the probability of high prices is the same as that for low prices. The price at the fiftieth percentile (the median price) may be $40/MWh, for example, while the lowest half-hourly price experienced is $15/MWh but the highest is $12,500/MWh.

Retailer contract strategies are intended to fix their forward cost commitments and insure against such high price events.

This skewed nature of the distribution of potential price outcomes means that the mean of such possible outcomes is higher than the median. Over time prudent retailers will want to be covered for the mean potential outcome. To insure against an outcome higher on the distribution of possible price outcomes would be to over-insure – in other words to select and pay for a higher level of risk averseness than is prudent.

The median of the distribution represents the annual load weighted price which would be occur under normal weather and outage conditions and would be expected to be exceeded one year in two. On the other hand, the mean of the price distribution provides an estimate of the price which a prudent retailer would be prepared to pay for energy over time to account for weather and outage risk.

Each tariff has a different load profile and would have a different distribution of the annual load weighted price and a different mean. Again the mean of the annual load weighted price distribution for each tariff represents the price a prudent retailer would be prepared to pay for energy to supply the load associated with that tariff.

In affect Approach 3 assesses the stochastic influences on the market. The inputs ACIL Tasman considers to be stochastic are those that are not possible to predict on a short-term basis – namely plant availability (in particular that resulting from forced or unplanned outages) and variation in demand due to variation in weather.

Variations in weather and plant availability affect the demand and supply balance and generator bidding behaviour in two ways:

- a coincidence of higher demand and reduced plant availability will most likely result in higher price outcomes
- a year with a mild winter and summer as well as a lower propensity of coincident outages will most likely result in lower price outcomes.

The purpose of modelling the variation in weather driven demand and plant availability is to estimate a distribution of future load weighted annual prices. In effect, the modelling allows for projections of likely variations in outcomes across the range of possible weather driven demand and outage inputs and a more robust method for establishing mean expected outcomes.

In developing this distribution of annual prices for 2012/13, ACIL Tasman makes the assumption that long-term influences on the market and the plant schedule remain unchanged.

3.3.2 Steps involved in Approach 3

Approach 3 involves the following steps:

Step 1. estimate the load traces for each retail tariff in the Energex area for 2010/11 based on interval meter recordings, annual energy consumption profiles for each tariff, overall load trace and net system load profile for Energex

Step 2. estimate 40 years of load data for the NEM regions and Energex tariffs at 2012/13 load levels based on temperature data over the past 40 years, load trace and temperature data for 2010/11 and the energy and demand forecasts for 2012/13 from AEMO and AER.

Step 3. establish 20 plant outage scenarios for the NEM

Step 4. estimate 820 years (41 years of load in combination with 20 outage scenarios) of half hourly prices for Queensland using *PowerMark,* an ACIL Tasman proprietary model of the NEM

Step 5. estimate the annual price distribution for each retail tariff in the Energex area by calculating 820 annual load weighted prices by using the loads from Step 2 and prices from Step 4

Step 6. find the mean of the 820 annual price estimates to use as the cost of energy for each tariff in the Energex area in 2012/13 and apply the Energex distribution loss factor (DLF) as published by Australian Energy Regulator and a load weighted Marginal Loss Factor (MLF) for the Energex area to allow for transmission losses from the reference node

Step 7. add a further premium to account for other costs and risks associated with energy purchase

Step 1: Estimate the Energex retail tariff load traces

To enable the estimation of the Energex retail tariff load traces the following data will be used:

- half hour load traces for each Transmission Node Identities (TNI) for Energex area from AEMO via the Authority to provide an overall load trace for Energex
- controlled load traces from the AEMO website
- interval meter data for Energex area customers to establish load traces for the various commercial and industrial tariffs
- 400 domestic customer interval meter recordings from Energex to estimate a residential load trace
- net System Load Profile (NSLP) for Energex from the AEMO website to be used for estimation of load traces for tariff groups without interval metres
- customer usage profiles for each tariff from Energex to be used to uplift the various load traces to represent the full load in each tariff
- Energex forecasts of system summer and winter peaks and annual energy submitted to the AER to be used in estimation of the Energex overall load trace for 2012/13

These data sources will enable the estimation of the retail tariff load traces adjusted where necessary to add to the overall for Energex load trace based on the TNIs allowing for the distribution losses.

Step 2: Develop 41 years of load traces each representing 2012/13

Development of 40 annual load traces for the total of NEM region and retail tariffs in the Energex area is based on 41 years of capital city temperature data from 1970/71 to 2010/11 and half-hourly load traces for the NEM regions and retail tariffs in the Energex area from Step 1for 2010/11. Under this approach each day in each of the 40 years would be populated by load traces selected from 2010/11 data set of the same day type and season with the closest matching temperature conditions.

Matching the temperature is achieved by finding the closest least squares match between the temperature profile for that day and the temperature profile for a day in the 2010/11 load data year across all NEM regions. Once the day in 2010/11 of the same day type and season that best matches the temperature profile of the day in question is identified then all the associated NEM regional and retail tariffs in the Energex area load traces for that day are inserted in the day in question. Data is chosen on a daily basis in this way because we wish to preserve the relationship between the NEM regional loads traces and retail tariff load traces in the Energex area.

This procedure produces 41 years of load traces which represent 2010/11 with 40 developed from past temperature data and the actual load traces for 2010/11.

Using a non-linear transformation the 41 years of load data are adjusted to match the AEMO 2011 ESOO forecast for 2012/13 for each NEM region and the consistent forecast for the Energex area from the Australian Energy Regulator (AER). This involves matching the forecast annual energy for each of the 41 years and matching the peak demand across the whole 41 years with the 10% POE (probability of exceedance) summer peak demand for 2012/13.

Step 3: Develop 20 sets of unplanned outages across the NEM

There is a price risk associated with power station forced outages which needs to be accounted for in calculating the cost of energy. The plant availability (outage) can have a significant bearing on pool price with outages of larger plant or combinations of smaller plant generally resulting in higher prices.

In *PowerMark* modelling the timing and duration of planned outages are fixed and pose little or no price risk whereas the timing and duration of forced or unplanned outages are random and introduce price risk. *PowerMark* allows random forced outages for each generator up to a predetermined level. This forced outage level is drawn from published documents and NEM data. In constructing the *PowerMark* data base we randomly assign to each generator unit a set of half-hourly forced outages, which reflect that unit's observed forced outage rate (with any anomalies removed). Each power station has different forced outage characteristics and this is also reflected in the *PowerMark* modelling.

Using binomial probability theory ACIL Tasman has simulated 20 sets of forced outages. This process has allowed a range of outage outcomes to be produced. The most important factor in outages is coincidence – if a number of units are forced out at the same time, volatile prices usually result. The process used to simulate the outage sets allows these sorts of coincidences to be represented appropriately in the sample.

Step 4: Estimate pool prices across the 820 data years

Combining the 41 years of load data adjusted to 2012/13 levels and 20 outage scenarios to create 820 years of data for input to *PowerMark* to produce 820 years of half hourly prices representing 2012/13. These half hourly prices represent a range of prices which encompass the likely weather and outage effects which could emerge in 2012/13. The prices produced by the *PowerMark* modelling are at the South Pine regional reference node for Queensland.

Step 5: Estimate the annual price distribution for each retail tariff

This step involves calculating 820 annual load weighted prices by using the half hourly loads traces adjusted to 2012/13 levels from Step 2 and Queensland half hourly prices from Step 4. This process is repeated for each retail tariff in the Energex area using the Queensland pool price from step 4 and the retail tariff load traces from Step 2.

This process produces 820 annual load weighted pool prices for each retail tariff to form a price distribution for each retail tariff in the Energex area for 2012/13.

Step 6 Find the mean of the price distribution and applying a distribution loss factor

Find the mean of each of the retail tariff price distributions established in Step 5. These mean prices represent the price at the Queensland reference node for each retail tariff which and the overall for the Energex area in 2012/13 which a retailer would be prepared to pay accounting for weather and outage risks.

To bring these retail tariff prices from the Queensland regional reference node to the customer terminals requires the application of a distribution loss factor (DLF) for Energex as published by AER and load weighted Marginal Loss Factor (MLF) for the Energex area to allow for transmission losses from the reference node.

Step 7: Add a further premium to account for other costs and risks associated with energy purchase

There are a number of other costs and risks faced by retailers in purchasing energy for retail customers as discussed below. The allowance for these other costs and risks will need to be added to the energy purchase costs for each tariff established in Step 6

The variation in weather and plant availability discussed above causes some uncertainty in expected pool price outcomes and as explained above this risk is mitigated by retailers if they insure against the mean rather than the median price.

There are of course other factors that are likely to influence energy purchase costs and these would include:

- counterparties to hedge contracts may have different risk profiles and risk appetites meaning that they may be prepared to pay more than the mean of the price distribution. However, it is assumed that this would not add to the contract prices paid by a prudent representative retailer.
- regulatory changes pose a risk with the potential to either increase or reduce EPC. This risk is best assessed on a case by case basis for particular regulatory proposals. At this time we are unable to identify any proposed regulatory changes which need to be taken into account for 2012/13.
- contracts also tend to have a reactionary component – forward contracts being offered or negotiated at a time of high price volatility tend to be higher in price than they would be otherwise, and vice versa. It has been assumed that this aspect will not impact contract costs for 2012/13.
- contracts with longer tenor or commencing later may have an additional cost component reflecting time value. Making allowance for the time value component in electricity contracts would appear justified and the proposed approach is discussed below.

Based on analysis of the historical time trend of annual contracts ACIL Tasman believes that a 0.5% allowance for each six month period that contracts are purchased in advance to reflect the time value would seem reasonable.

The overall time value adjustment is then found by applying the above six monthly time value allowances to the hedge volume assumed for that six month period.

The resultant time value adjustment would be applied to the weather and plant outage adjusted price being the mean of the annual price distribution as discussed above.

Typically the bulk of annual hedging would be undertaken in the period beginning three years out and largely be concluded a few months before the start of a contract term.

Table 1 shows the calculation of the time value adjustment. The hedge volume is the percentage of total planned hedges to be contracted in each six month block. The time value allowance is determined by the rule set out above. The volume and premium are multiplied to establish a weighted average premium across all contracts which in this case totals 1.15 percent.

Table 1 **Time value adjustment**

Timeframe	Hedge volume %	Time value allowance	Time value adjustment
30-36 months out	10%	2.5%	0.25%
24-30 months out	10%	2%	0.2%
18-24 months out	20%	1.5%	0.3%
12-18 months out	30%	1%	0.3%
6-12 months out	20%	0.5%	0.1%
0-6 months out	10%	0%	0%
Total			1.15%

Data source: ACIL Tasman analysis

3.3.3 Comments on Approach 3

In common with the market modelling approach outlined above, the main criticism of this approach would be its lack of transparency in that it relies on market modelling using propriety software to estimate the half hourly pool prices. However, the necessary input data is available and the approach is based on sound theoretical foundations.

The approach recognises that it is appropriate for a prudent retailer to hedge risks through energy purchase contracts which will attract a premium over the expected spot market price under "normalised" weather, outage and other conditions. Under the approach it is contended that the retailer will be prepared to pay price of electricity which is represented by the mean of possible prices outcomes.

The approach has been developed and used by ACIL Tasman to evaluate energy costs for industry participants for many years. Furthermore, the approach provides robust estimates of likely energy purchase costs particularly given the competitive market for energy purchases that exists.

On this basis and given the inappropriateness of Approach 1 and the current poor liquidity in 2013 contract trading ruling out the use of Approach 2, ACIL Tasman is of the opinion that Approach 3 represents the most reasonable and robust approach to estimating energy costs available today.

3.4 Approach 4 - Combination of LRMC and market based approaches

This methodology has been included as it was used for the calculating the BRCI however it is not proposed for this exercise on the basis that the LRMC approach is not considered an appropriate methodology for the reasons outlined in Section 3.1. This means that using the LRMC in combination with a market based approach is not considered appropriate.

4 Other energy purchase costs

4.1 LRET

The cost of the LRET scheme is found by applying the Renewable Power Percentage (RPP) to the LGC price to establish the cost per MWh supplied to customers. Spreading the cost to the various tariffs is a relatively simple matter as the cost will be expressed as a cost per MWh. There is no uncertainty over the Renewable Power Percentage (RPP) component of the calculation as this is published by ORER. The methodology for determining the price for LGCs is not as straight forward.

ACIL Tasman understand that the vast majority of LGCs are acquired by retailers through long term contracts with wind farms or through wind farm ownership. However, the prices in these contracts are not available for use in estimating the cost of the LRET scheme. We also note that retailer submissions indicate the volume of LGC acquired through the traded market is small by comparison and that the market price may not a reliable indicator of costs and that it would be more appropriate to base the estimation of the cost of LRET by using the long run marginal cost of wind generation.

However, a low volume of trading does not necessarily mean that the traded prices are an unreliable source on which to base the estimation of the cost of the scheme. ACIL Tasman has examined the market price over recent years and has observed that that the market price has reacted as one would expect to prevailing market conditions. For example, between April and December 2010 the AFMA REC (now LGC) price for the year ahead fell from $46.41 to $29.29 in a period of significant and growing over supply. Since then with the split of the scheme into LRET and SRES on 1 January 2011 and an adjustment to the target, the LGC price for the year ahead has recovered to $40.53 in October 2011.

For calculation of the BRCI the average market price of LGC recorded by AFMA over the previous two years was used. ACIL Tasman is of the view that this methodology is also adequate for the 2012/13 retail tariffs.

4.2 SRES

The cost of SRES is found by applying the Small-scale Technology Percentage (STP) to the STC price to estimate the cost per MWh to apply to each tariff. However the approach to be followed in estimating the STP and STC is not clear and this is discussed below.

The SRES is somewhat more problematic in that the final Small-scale Technology Percentage (STP) will not be known for the second half of the 2012/13financial year until after the tariff year commences. However the ORER publishes an estimate for the calendar year applying in the latter half of the financial year which ACIL Tasman suggests would suffice for purpose of calculating the cost of the SRES for use in the EPC for the 2012/13 retail tariffs.

The current official price for STCs is $40/STC and STCs are available to retailers from the ORER clearing house for this price. The clearing house price can be changed at any time by the Minister and as such the expected prevailing price for 2012/13 would need to be considered. However the clearing house works on a first in first out basis which has meant that the installers of solar photovoltaic systems have experienced significant delays in receiving payment for STCs which has caused cash flow problems for some. As a result an active market for STCs has developed outside the clearing house to allow installers to gain quicker access to payment for STCs from retailers. the current market price for STCs is well below the official $40 price.

This raises the question whether ACIL Tasman should take both clearing house price and market price into consideration when determining the price for STCs. To use the market price would pose a number of difficulties including the need to forecast the proportion of STC likely to be traded in the tariff year.

Given that the STC market is for spot sales and not a forward market and given that volumes traded are not available ACIL Tasman proposes using the clearing house price as the price for STCs.

4.3 GEC

For the 2011/12 BRCI the cost of compliance with the Queensland GEC scheme was based on a two year average of the AFMA prices for GECs.

However, retailers have generally stated that this methodology of relying entirely on the AFMA market prices underestimates the cost of the GEC scheme to retailers which have entered long term supply contracts or invested in generation to secure these certificates at prices which are much higher than those currently in the market. However information on these contractual arrangements is not available and market price information is the only reliable source of GEC costs.

ACIL Tasman's view is that where a market price for inputs to the calculation of retailers' EPC can be sourced reliably and consistently each year it should provide the best guide to the cost of compliance with the scheme. However given that GECs have been acquired by various means including long term contracts and the fact that the GEC market is now oversupplied with low prices and very thin trading, it is proposed that the AFMA weekly GEC prices be averaged over an extended period of 208 weeks or 4 years as follows

- for 2012 - from 1 Dec 2007 to 31 Dec 2011
- for 2013 - from 1 Mar 2008 to 31 Mar 2012

The cost of compliance with the GEC scheme for the 2011/12 BRCI was estimated at $0.65/MWh.

4.4 NEM retailer costs

ACIL Tasman proposes to use the same methodology as used for the BRCI to estimate the cost of market fees and ancillary services.

4.4.1 Market fees

NEM participant and FRC fees are payable by retailers to AEMO to cover operational expenditure. The estimated NEM participant and FRC fees will be taken from AEMO's draft budget NEM fees for 2012-13.

For the 2011/12 BRCI these fees were estimated at $0.39/MWh.

4.4.2 Ancillary services

Ancillary services costs will be found by aggregating settlements data for ancillary service payments for Queensland provided by AEMO for the latest 52 week period and dividing by the MWh used in that period. The estimated cost of ancillary services for the 2011/12 BRCI was $0.45/MWh.

5 Application of cost of energy to individual retail tariffs

A key requirement of the Minister's Direction was that retail tariffs are to be cost reflective. This requirement has led to the development of a methodology which will allow such estimates.

5.1 Estimating tariff energy costs

The cost of supplying the individual tariffs in 2012/13 will be the taken as the mean of the price distribution for each tariff developed using the same stochastic analysis based on the 820 years of price data. While the Queensland pool prices for each half hour remain the same for each tariff, the distribution of the 820 annual load weighted prices for each tariff will vary due to the variations in the tariff load profiles. Finally the mean of each of the tariff price distribution will be uplifted to account for time value in contracting.

The prices for individual tariffs under Approach 3 will involve the following steps

Step 1. Develop load traces for each tariff in the Energex area using customer number, energy consumption and interval metering supplied by Energex. For the residential sector the interval metering results for 400 customers will be used to develop the raw load shape for this tariff type. The load traces for the two controlled load tariffs published by AEMO will be used for these tariff types. These individual load traces will be adjusted to match the overall Energex load trace found by from totalling the relevant TNIs.

Step 2. The tariff load traces will be corrected for weather along with the NEM regions and Energex total as described in Section **Error! Reference source not found.** to give standard 50% POE tariff load traces. Section **Error! Reference source not found.**. explains the process of arriving at a50% POE load traces for the NEM regions, the Energex network area and the individual network tariffs. Each of these load traces is based on exactly the same day selection from 2010/11 so they align perfectly day by day.

Step 3. The Energex peak and energy forecasts which are consistent with the AEMO 2011 ESOO along with the peak demand and energy from the standard 50% POE load traces will be used to estimate the peak demand and annual energy for each tariff type in the Energex area. The standard 50% POE tariff load traces will be adjusted to match the peak demand and energy forecasts by tariff for 2012/13.

Step 4. Undertake stochastic analysis for each of the tariff types to establish mean of the price distribution to use as the cost of energy allowing for weather and outage risks

Step 5. Uplift the estimates in Step 4 to allow for time value of contracting

5.2 Recovering EPC in tariffs

The final step is to determine the method by which the EPC is to be recovered in each of the tariffs. The suggested approach has been guided by the requirement that tariff prices should be cost-reflective. In view of this there is to be no fixed charge in the energy purchase component so all the EPC will be recovered by applying a charge or charges linked to energy consumption.

The approach to individual tariffs is as follows:

- for all tariffs not using an interval meter (e.g. inclining block domestic, controlled, unmetered, flat commercial and industrial) the EPC will be recovered by a charge or charges on consumption only.
- for the domestic time-of-use (TOU) tariffs there will be different allowances in the price for EPC for peak, off-peak and shoulder times and where necessary for week days and weekends. These prices will be determined by combining the standard 50% POE tariff load trace with the expected pool prices from the pool price modelling and adding percentage so that these prices equate to the mean of the load weighted price distribution from the stochastic analysis plus the allowance for the time value of contracts.
- for other interval metered tariff customers the peak and off-peak prices will be established using the same methodology as TOU tariffs.