Estimated energy purchase costs for 2012/13 retail tariffs

Estimated energy purchase costs by retail tariff for use by the Queensland Competition Authority in its Draft Decision on retail electricity tariffs for 2012/13

March 2012

ACIL Tasman

Economics Policy Strategy

ACIL Tasman Pty Ltd

ABN 68 102 652 148
Internet www.aciltasman.com.au

Melbourne (Head Office)

Level 4, 114 William Street
Melbourne VIC 3000

Telephone (+61 3) 9604 4400
Facsimile (+61 3) 9604 4455
Email melbourne@aciltasman.com.au

Brisbane

Level 15, 127 Creek Street
Brisbane QLD 4000
GPO Box 32
Brisbane QLD 4001

Telephone (+61 7) 3009 8700
Facsimile (+61 7) 3009 8799
Email brisbane@aciltasman.com.au

Canberra

Level 1, 33 Ainslie Place
Canberra City ACT 2600
GPO Box 1322
Canberra ACT 2601

Telephone (+61 2) 6103 8200
Facsimile (+61 2) 6103 8233
Email canberra@aciltasman.com.au

Perth

Centa Building C2, 118 Railway Street
West Perth WA 6005

Telephone (+61 8) 9449 9600
Facsimile (+61 8) 9322 3955
Email perth@aciltasman.com.au

Sydney

PO Box 1554
Double Bay NSW 1360

Telephone (+61 2) 9389 7842
Facsimile (+61 2) 8080 8142
Email sydney@aciltasman.com.au

For information on this report

Please contact:

Marcus Randell
Telephone (07) 3009 8709 or 30098700
Mobile 0404 822 319
Email m.randell @aciltasman.com.au

Contributing team members

Paul Breslin
Paul Hyslop
Richard Lenton
Martin Pavelka
Cara Chambers

Contents

List of figures

List of tables

1 Introduction

This report provides estimates of expected energy purchase costs for use by the Queensland Competition Authority (the Authority) in developing retail electricity tariffs for 2012/13.

Retail tariffs are made up of three components: network costs, retailing costs and energy purchase costs. It is the energy purchase costs component which is the focus of this ACIL Tasman report. In accordance with the Ministerial Delegation[1] and the brief provided by the Authority, the methodology developed by ACIL Tasman is to provide an estimate of energy purchase costs which reflect the actual cost of purchasing electricity. Energy purchase costs (EPC) comprise wholesale energy purchase costs and other costs energy purchase costs associated with renewable energy incentives and market fees.

In accordance with the brief provided by the Authority the energy purchase costs presented in this report are estimates of the actual EPC expected to be faced by independent electricity retailers in 2012/13 buying energy out of the National Electricity Market (NEM). The estimates of EPC include contracting costs and premiums or a margin over the estimated median pool price to account for the contracting premiums and other costs.

1.1 History

This report follows a draft methodology report prepared by ACIL Tasman[2] and released in November 2012 along with the the Authority's Draft Methodology Paper- Regulated Retail Electricity Prices 2012-13[3]. Submissions from stakeholders were sought and received by the Authority and a workshop with stakeholders was organised by the Authority in November 2011.

In its draft methodology report to the Authority ACIL Tasman examined a number of alternative methodologies for estimating WEPC which included:

- contract hedging
- long run marginal cost (LRMC) of generation
- price distribution

[1] Ministerial Delegation - September 2011

Found at: http://www.qca.org.au/files/ER-NEP1213-QLDGovtDME-CertDeleg-0911.PDF

[2] ACIL Tasman - Draft methodology for estimating energy purchase costs - November 2011

Found at http://www.qca.org.au/files/E-ACIL-DraftMethPaper-EstimatingEnergyPurchaseCostsSep11-1111.pdf

[3] Queensland Competition Authority - Draft Methodology Paper - Regulated Retail Electricity Prices 2012-13 - November 2011

Found at: http://www.qca.org.au/files/E-QCA-DraftMethPaper-RegulatedRetailElectricityPrices1213-1111.pdf

- combination of above approaches.

ACIL Tasman favoured the price distribution approach mainly because electricity contracts and futures covering the first half of 2013 were very thinly traded and contract prices for this period were not considered reliable.

In its draft methodology paper the Authority also supported using the price distribution approach for 2012/13 citing similar concerns but indicating that the hedging approach had a number of advantages and when contract prices were traded normally this would likely be the approach used in future years.

In both the workshop and submissions key stakeholders expressed the concern that the price distribution approach, which had not been used before in setting energy purchase costs in regulated retail electricity tariffs, lacked transparency They were generally not convinced that it would provide robust estimates of the wholesale EPC facing retailers in 2012/13.

Most retailers favoured the LRMC approach. However, as discussed in both the ACIL Tasman methodology report and the Authority's draft methodology paper, this methodology does not account for prevailing market conditions and therefore is unlikely to reflect the actual wholesale energy purchase costs faced by retailers in 2012/13 as specified in the Ministerial Delegation.

The ACIL Tasman methodology report and the Authority's draft methodology paper also suggested an approach to estimating other energy purchase costs associated with renewable energy schemes and market fees, applying a similar method to that used in calculating the benchmark retail cost index (BRCI) in previous years. This approach was generally accepted by stakeholders.

1.2 Response to concerns

In response to stakeholder concerns over the price distribution approach, ACIL Tasman undertook further detailed analysis of contract volumes and prices to assess the viability of using a contract hedging approach as a possible alternative to the price distribution approach. The analysis showed that, while volumes were lower than would be expected based on past levels, contract prices for the first two quarters of 2013 seemed to be consistent and relatively stable since the passing of the carbon pricing legislation in November 2011. On this basis, alternative estimates of the wholesale EPC using the contract hedging approach are presented along with the estimates from the price distribution approach.

1.3 Methodology for estimating wholesale EPC

1.3.1 Price distribution

In its methodology report to the Authority ACIL Tasman suggested as the preferred approach a "price distribution" method, which is explained further below. This approach was considered because of the difficulty in sourcing reliable data on forward contract prices, mainly arising because of uncertainty in the market over the impact of the tax on CO_2 emissions from 1 July 2012. In general the stakeholder responses were not supportive of the price distribution methodology, in some cases because of the perceived complexity of the approach and in others because it does not attempt to replicate the process the retailers follow in buying forward hedge contracts and then buying from the NEM spot market. . When it was under consideration by stakeholders there was also no previous experience with the approach and no indication of the results the methodology would provide.

1.3.2 LRMC

In their response to the draft methodology retailers generally favoured using a long run marginal cost (LRMC) of generation approach even though ACIL Tasman had indicated in its methodology report that LRMC was not an appropriate approach, mainly because it does not necessarily reflect prevailing market conditions, such as over or under supply and as a result can easily over or under state the wholesale EPC.

Similar concerns were expressed in the Authority's draft methodology paper and at the November 2011 workshop held by the Authority to discuss the draft methodology. Furthermore, given that it may not reflect market conditions, the LRMC approach would not be consistent with Ministerial Direction which stated that the Authority should ensure its price determination has regard to the actual costs of supplying electricity.

1.3.3 Hedging approach

The more widely used and understood methodology of developing a hedge book and using market contract prices similar to that used for estimating the Benchmark Retail Cost Index (BRCI), was seen as more desirable by most respondents to the Authority's draft methodology paper and participants at its workshop. Most agreed, however, that the low traded volume for 2013 because of the impending introduction of a carbon tax, meant that there were concerns about the reliability of the contract price data.. However, given the concerns over the price distribution methodology and given that trade volumes have increased since November and are likely to increase further before the

Authority's final decision due in May, we have developed estimates using a hedging approach.

Apart from problems arising from the thinly traded market for 2013, the hedging methodology also requires the determination of an appropriate hedging strategy. ACIL Tasman believes that the significance of this problem can be tested by applying the contract strategy in a wide variety of potential load and pool price outcomes. This is achieved by setting the contract volumes against a median weather/price year then running the model against the 410 weather/outage years used in the price distribution approach.

1.4 Suggested approach

In order to provide support for the Authority's Draft Decision the approach adopted for this report is to provide wholesale energy purchase cost estimates using both the price distribution approach and the hedging approach.

The Authority and stakeholders will then have available estimates from both methodologies. The approach is designed to place the Authority in a position where it is able to decide how to best use the results of the two methodologies in determining the regulated retail tariffs for 2012/13.

The methodology which uses the mean of the price distribution assumes that generators and retailers have the same risk profiles and that both have the same view on the level of the expected market price. To allow for differing risk profiles and the fact that the counterparties could well have differing views of the expected price is problematic under this approach. For the 2012/13 exercise no further premium is added. This is because the results for the contract hedging approach are generally slightly lower than the mean of the price distribution (see Figure 15) which may be suggesting that the oversupplied market in 2012/13 is providing an opportunity for retailers to negotiate contract prices below expected market prices.

On this basis ACIL Tasman recommends the use of the contract hedging approach for estimating the wholesale EPC for 2012/13 and also for future years, particularly if there are reasonable contract volumes traded and prices provide a reliable guide to the costs faced by retailers in hedging activities. Using the median price of 410 possible annual prices from the hedging approach as the estimate for the wholesale EPC, as presented in this report, is considered superior to weighting the 50 percent, 10 percent and 90 percent POE price forecasts as used previously in the BRCI. However, the contract strategy is shown to remove almost all the volatility in annual prices (see Figure 13) and so prices from the hedging approach based on a single 50 percent POE load forecast should provide a reasonable estimate for the wholesale EPC in future years.

2 Price distribution approach for estimating the wholesale EPC

2.1 Background

As outlined in the ACIL Tasman methodology report, the price distribution approach involves modelling a large number years to represent the possible range of market outcomes in 2012/13 due to variations in weather and plant outage. A single load weighted average price is then calculated for each of the years representing 2012/13. The resultant distribution of these annual average load weighted prices represents the possible pool price variations faced by electricity retailers in 2012/13 due to weather and outage. It provides an estimate of the median and the mean (average or expected) of potential prices in 2012/13.

The price distribution is skewed towards lower prices (to the left), its mean is higher than its median. ACIL Tasman analysis estimates that the mean price occurs around the 66th percentile of the distribution. By definition the median price occurs at the 50th percentile of the distribution with half the prices in the distribution being lower and half higher.

To provide an idea of the spread of prices in the distribution, for the Net System Load Profile (NSLP) for Energex, ACIL Tasman estimates that the annual average load weighted average prices for 2012/13 will range from a low of $45.19/MWh to a high of $146.55/MWh with a median price of $58.02/MWh and a mean of $63.97/MWh. These prices all include an allowance for the carbon tax of $23.00/tCO$_2$-e.

The mean price is an estimate of the price which a retailer would expect to pay in the event that the retailer purchased all of its electricity requirements out of the electricity pool and held no electricity hedging contracts. Furthermore, in the absence of any consideration of risk, the mean price can be interpreted as the maximum price that a retailer would pay to maximise its position on an expected outcome basis. The lack of consideration of risk in effect assumes that the retailer would have the financial resources to be able to manage the worst potential outcomes. In a worst case scenario for 2012/13, for example, ACIL Tasman estimates that the price to purchase the Energex NSLP could be as high as $146.55/MWh, which is more than double the expected or mean price of $63.97/MWh.

ACIL Tasman recognises that retailers operate as a margin business - i.e. they purchase electricity and sell it to consumers and make profits on the difference or margin between the purchase and sale price less the costs of running the business. One of the key costs in a retail business is working capital. Excessive working capital costs would make a retailer uncompetitive with its peers. In the absence of electricity contracting, the variation in electricity purchasing costs would require significantly higher working capital costs. Additional very large lines of credit (at a cost) would also be required to cover rarely occurring periods of extreme market price volatility. Otherwise the uncontracted retailer would face the real possibility of financial failure.

Electricity contracting shifts the risk from retailers to the seller, usually generators seeking to sell contracts to reduce the risk of revenues that vary with the volatility of spot market prices (the generator risk is inversely correlated with the retailer risk). Similar to retailers, in the absence of consideration of risk, the mean price is the minimum price that a generator would accept to maximise its position on an expected outcome basis. In practice, generators also take into account risk because they have obligations to meet the cost of operating their generation business, including the interest on and the repayment of any debt.

In the absence of consideration of risk for both retailers and generators, the electricity contract equilibrium price should be the mean (or expected) price outcome as retailers would pay no more and generators would accept no less. However, both retailers and generators typically operate under sophisticated risk management policies that are usually based on considering earnings at risk. This requires them to purchase or sell electricity contracts even where the outcome is less optimal than the expected outcome.

In the event that generators are more risk averse than retailers, the contract price would be expected to be below the mean price. In the event that retailers are more risk averse than generators, the contract price would be expected to be above the mean price.

Efficient retailers are generally thinly capitalised compared to generators. The adverse pool price risk for retailers tends to be very high prices which can occur very quickly with extreme consequences over a very short period of time. Generators typically have much stronger capitalisation and working capital and price variation tends to have much less impact on the overall cost base. The adverse pool price risk for generators tends to be very low prices, which usually manifest over longer periods of time. This leads ACIL Tasman to conclude that, in general, retailers are more risk averse than generators, which implies that the electricity contract equilibrium price should be greater than the mean price of the price distribution.

An example of a retailer approach to risk was contained in a recent report to shareholders by AGL which states:

> AGL hedges its exposure to electricity demand and price volatility by using a combination of owned or controlled physical electricity generation assets and forward agreements and option contracts entered into with other electricity market participants.
>
> AGL hedges its electricity exposures in accordance with a Board approved, and independently reviewed, risk management policy. The policy sets limits on the amount of earnings at risk from movements in electricity demand and electricity prices. The hedge cover that is put in place at any time is based on forecasts of weather patterns over peak demand periods of winter and summer, and on a statistically based assessment of the correlation of customer demand for electricity with variations in temperature. AGL's hedging does not attempt to cover extreme events which statistical analysis indicates will occur less frequently than once every 20 years. The cumulative cost of purchasing hedging instruments to mitigate such extreme exposure will substantially exceed the potential occasional losses from such an unusual sequence of events.

As outlined by AGL, an efficient retailer will contract to a level where the exposure to high prices is kept at an acceptable level and keeping the prospect of failure to a reasonable level. The level of contract protection sought by a retailer, therefore, varies depending on their appetite for risk and their financial capability to ride out a high price period.

ACIL Tasman is not able to estimate with any accuracy the extent to which the difference in risk aversion would shift the electricity contract equilibrium price above the mean of the price distribution and has not included an allowance for this factor in the price distribution estimates.

In addition, as suggested in our previous methodology report, consideration needs to be given to the cost of pre purchasing contracts estimated at a further 1.15 percent. It was stated that 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 percent 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.

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.

2.2 Modifications to the price distribution methodology

The methodology followed is as described in ACIL Tasman's methodology report except that:

- 410 data years have been used not 820 (41 load years and 10 outage scenarios, not 20). Testing of the approach showed that the improvement in accuracy was negligible when using 820 data years rather than 410.
- Energy purchase costs for residential and small business customers using less than 100MWh per annum have been calculated using the net system load profile (NSLP). The methodology report envisaged basing the energy purchase costs on the load profiles of the individual retail/network tariffs but stakeholders both in submissions and at the workshop correctly pointed out that the individual profiles were not relevant as retailers are charged for metered energy assuming the NSLP for pool purchases to supply these small customers regardless of the customers' actual load profile.
- Selecting from four years (2008/09 to 2010/11) not just 2010/11 to construct the 37 year load data set. This again was in response stakeholder comments that selecting from one year severely limited the richness of the constructed load data set.
- Using a revised load forecast for Queensland released by Powerlink in its Updated 2011 Annual Planning Report (APR).

2.3 Outline of methodology

The main steps in the methodology are as described in the methodology report as follows

Step 1. Estimate load traces for four years: Estimate the load traces for retail/network tariffs in the Energex area for 2010/11 for business customers using greater than 100MWh per annum based on interval meter recordings, annual energy consumption profiles for each tariff. Estimate the load traces for the >100MWh customers to cover the previous three years (2007/08 to 2009/10). The past data is then adjusted to the 2010/11 levels by applying a quarterly growth factors.Extract the Energex and Ergon Energy NSLP load traces for the four years from 2007/08 to 2010/11 from the AEMO published data. The Energex NSLP is used to estimate the wholesale EPC for <100MWh customers and the the Ergon Energy NLSP is used to estimate the wholesale EPC applying to >100MWh customers in the Ergon Energy area.

Step 2. Develop 41 years of load traces each representing 2012/13: Create 41 year load trace data set: Populate 37 years (1971/72 to 2006/07)with load trace data for each NEM region, the Energex NSLP, control tariff and interval metered customers by tariff and the Ergon Energy NSLP.. These profiles are selected day by day from four years of load data (2007/08 to 2010/11) by matching the daily temperature profile and day type (season and working non-working days) for each day over the past 37 years across the NEM to a day of the four years of actual load data .

The resultant regional load traces are then adjusted to the 2012/13 level by adjusting them to match the 2012/13 demand and energy forecasts forQueensland from Updated 2011Annual Planning Report (APR) and for other NEM regions from the AEMO 2011 ESOO. The adjustment to match the load forecast for 2012/13 is across the 41 years. Total energy under the load trace is forced to equal 41 times the forecast annual energy in each NEM region and peak demand for the 41 years is made to match the 10 percent probability of exceedence (POE) summer demand forecasts in each region.

Step 3. Develop 10 plant outage scenarios for the NEM - Using binomial probability theory ACIL Tasman has simulated 10 sets of forced outages.

Step 4. Estimate pool prices across the 410 data years: Estimate 410 years (41 years of load in combination with 10 outage scenarios) of hourly prices for Queensland using *PowerMark,* an ACIL Tasman proprietary model of the NEM

Step 5. Estimate the annual average load weighted price for each retail tariff: Estimate the annual price distribution for the NSLP, each of the two control tariffs, and for SAC, CAC and ICC customers and unmetered supply in the Energex area by calculating 410 annual average load weighted prices by using the loads from Step 2 and prices from Step 4

Step 6. Find the mean of the price distribution and apply a transmission and distribution loss factor: Find the mean of the 410 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. Consider adding a risk premium: It could be argued that a risk adjustment should be made to allow for the difference in risk sensitivity of retailers and generators. If retailers are more sensitive to market price risk then the contract equilibrium price would be higher than the mean of the price distribution whereas if generators are more price risk sensitive then the equilibrium contract price would be below the mean of the price distribution. It is ACIL Tasman's opinion that retailers face a higher price risk and that the contract equilibrium price would settle above the mean of the price distribution. ACIL Tasman has been unable to quantify the likely size of this risk premium with any certainty and has made no allowance for it in the EPC estimate. This approach is supported by the fact that the contract hedge results for 2012/13 presented in Section 3 are generally lower than the mean of the price distribution suggesting there is there is no risk premium over the mean of the price distribution.

Step 8. Add an allowance for cost of pre-purchasing contracts - In addition consideration needs to be given to the cost of pre purchasing contracts estimated at a further 1.15 percent.

2.4 Data sources

The methodology uses data from a range of sources including those that are in the public domain and those that are not. Where possible the data sources will be available to stakeholders for review.

2.4.1 Generation cost and other data

The generator information used in the market modelling covers fuel and variable O&M costs, installed capacities, efficiencies, emission factors, planned and forced outage rates, auxiliary use, portfolio ownership structure, contract cover and minimum generation levels.

These data are contained in the generator data base used in the *PowerMark* modelling of pool prices. The estimates contained in this data base have been developed over the past 15 years and have been scrutinised by a wide variety of clients over this period. The sources of this data are many and include:

- annual reports
- gas price modelling using *GasMark*
- announced contractual arrangements for fuel
- ACIL Tasman estimates
- Non-sensitive information provided by clients
- AEMO reports

Summary data for Queensland power stations is provided in Table 1.

Table 1 **Details of Queensland generators used in pool price modelling for 2012/13**

Portfolio	Generator	Gen Type	Fuel	Capacity (MW)	Min Gen (MW)	Auxiliaries (%)	Thermal efficiency HHV (%) sent-out	Combustion emission factor (kg CO2-e/GJ of fuel)	VOM ($/MWh sent-out, 2011 $)	FOM ($/MW/year, 2011 $)
AGL	Oakey	Gas turbine	Natural gas	141	0	1.5%	32.6%	0.0513	$9.50	$13,000
AGL	Oakey	Gas turbine	Natural gas	141	0	1.5%	32.6%	0.0513	$9.50	$13,000
AGL	Townsville	cycle	Coal seam methane	160	133	3.0%	46.0%	0.0513	$1.04	$31,000
AGL	Townsville	cycle	Coal seam methane	80	67	3.0%	46.0%	0.0513	$1.04	$31,000
BBP	Braemar 1	Gas turbine	Natural gas	168	90	1.5%	30.0%	0.0513	$7.83	$13,000
BBP	Braemar 1	Gas turbine	Natural gas	168	90	1.5%	30.0%	0.0513	$7.83	$13,000
BBP	Braemar 1	Gas turbine	Natural gas	168	90	1.5%	30.0%	0.0513	$7.83	$13,000
CS Energy	Barron Gorge	Hydro	Hydro	30	15	1.0%	100.0%	0	$11.28	$52,000
CS Energy	Barron Gorge	Hydro	Hydro	30	15	1.0%	100.0%	0	$11.28	$52,000
CS Energy	Callide B	Steam turbine	Black coal	350	200	7.0%	36.1%	0.095	$1.19	$49,500
CS Energy	Callide B	Steam turbine	Black coal	350	200	7.0%	36.1%	0.095	$1.19	$49,500
CS Energy	Callide C	Steam turbine	Black coal	405	200	4.8%	36.5%	0.095	$2.70	$49,500
CS Energy	Gladstone	Steam turbine	Black coal	280	110	5.0%	35.2%	0.0921	$1.18	$52,000
CS Energy	Gladstone	Steam turbine	Black coal	280	110	5.0%	35.2%	0.0921	$1.18	$52,000
CS Energy	Gladstone	Steam turbine	Black coal	280	110	5.0%	35.2%	0.0921	$1.18	$52,000
CS Energy	Gladstone	Steam turbine	Black coal	280	110	5.0%	35.2%	0.0921	$1.18	$52,000
CS Energy	Gladstone	Steam turbine	Black coal	280	110	5.0%	35.2%	0.0921	$1.18	$52,000
CS Energy	Gladstone	Steam turbine	Black coal	280	110	5.0%	35.2%	0.0921	$1.18	$52,000
CS Energy	Kareeya	Hydro	Hydro	21	8	1.0%	100.0%	0	$6.15	$52,000
CS Energy	Kareeya	Hydro	Hydro	21	8	1.0%	100.0%	0	$6.15	$52,000
CS Energy	Kareeya	Hydro	Hydro	18	8	1.0%	100.0%	0	$6.15	$52,000
CS Energy	Kareeya	Hydro	Hydro	21	8	1.0%	100.0%	0	$6.15	$52,000
CS Energy	Kogan Creek	Steam turbine	Black coal	750	350	8.0%	37.5%	0.094	$1.25	$48,000
CS Energy	Mackay GT	Gas turbine	Fuel oil	34	0	3.0%	28.0%	0.0697	$8.94	$13,000
CS Energy	Wivenhoe	Hydro	Hydro	250	0	1.0%	100.0%	0	$0.00	$52,000
CS Energy	Wivenhoe	Hydro	Hydro	250	0	1.0%	100.0%	0	$0.00	$52,000
Ergon	Barcaldine	Gas turbine	Natural gas	55	27	3.0%	40.0%	0.0513	$2.37	$25,000
ERM	Braemar 2	Gas turbine	Natural gas	153	150	1.5%	30.0%	0.0513	$7.83	$13,000
ERM	Braemar 2	Gas turbine	Natural gas	153	0	1.5%	30.0%	0.0513	$7.83	$13,000
ERM	Braemar 2	Gas turbine	Natural gas	153	0	1.5%	30.0%	0.0513	$7.83	$13,000
InterGen	Callide C	Steam turbine	Black coal	405	200	4.8%	36.5%	0.095	$1.19	$49,500
InterGen	Millmerran	Steam turbine	Black coal	425.5	130	4.7%	36.9%	0.092	$2.81	$48,000
InterGen	Millmerran	Steam turbine	Black coal	425.5	130	4.7%	37.5%	0.092	$2.81	$48,000
Electricity Limited	Darling Downs	cycle	Natural gas	630	270	6.0%	46.0%	0.0513	$1.04	$31,000
Electricity Limited	Mt Stuart	Gas turbine	Liquid Fuel	146	0	3.0%	30.0%	0.0697	$8.94	$13,000
Electricity Limited	Mt Stuart	Gas turbine	Liquid Fuel	146	0	3.0%	30.0%	0.0697	$8.94	$13,000
Electricity Limited	Mt Stuart	Gas turbine	Liquid Fuel	126	0	3.0%	30.0%	0.0697	$8.94	$13,000
Electricity Limited	Roma	Gas turbine	Natural gas	40	0	3.0%	30.0%	0.0513	$9.50	$13,000
Electricity Limited	Roma	Gas turbine	Natural gas	40	0	3.0%	30.0%	0.0513	$9.50	$13,000
QGC	Condamine	cycle	Natural gas	140	0	3.0%	48.0%	0.0513	$1.04	$31,000
Rio Tinto	Yarwun	Gas turbine	Natural gas	168	143	2.0%	34.0%	0.0513	$0.00	$25,000
Stanwell - Tarong	Collinsville	Steam turbine	Black coal	31	20	8.0%	27.7%	0.0894	$1.31	$65,000
Stanwell - Tarong	Collinsville	Steam turbine	Black coal	31	20	8.0%	27.7%	0.0894	$1.31	$65,000
Stanwell - Tarong	Collinsville	Steam turbine	Black coal	31	20	8.0%	27.7%	0.0894	$1.31	$65,000
Stanwell - Tarong	Collinsville	Steam turbine	Black coal	31	20	8.0%	27.7%	0.0894	$1.31	$65,000
Stanwell - Tarong	Collinsville	Steam turbine	Black coal	31	20	8.0%	27.7%	0.0894	$1.31	$65,000
Stanwell - Tarong	Stanwell	Steam turbine	Black coal	360	190	7.0%	36.4%	0.0904	$3.18	$49,000
Stanwell - Tarong	Stanwell	Steam turbine	Black coal	360	190	7.0%	36.4%	0.0904	$3.18	$49,000
Stanwell - Tarong	Stanwell	Steam turbine	Black coal	360	190	7.0%	36.4%	0.0904	$3.18	$49,000
Stanwell - Tarong	Stanwell	Steam turbine	Black coal	360	190	7.0%	36.4%	0.0904	$3.18	$49,000
Stanwell - Tarong	Swanbank E	cycle	Coal seam methane	385	150	3.0%	47.0%	0.0513	$1.04	$31,000
Stanwell - Tarong	Tarong	Steam turbine	Black coal	350	140	8.0%	36.2%	0.0921	$7.42	$49,500
Stanwell - Tarong	Tarong	Steam turbine	Black coal	350	140	8.0%	36.2%	0.0921	$7.42	$49,500
Stanwell - Tarong	Tarong	Steam turbine	Black coal	350	140	8.0%	36.2%	0.0921	$7.42	$49,500
Stanwell - Tarong	Tarong	Steam turbine	Black coal	350	140	8.0%	36.2%	0.0921	$7.42	$49,500
Stanwell - Tarong	Tarong North	Steam turbine	Black coal	443	175	5.0%	39.2%	0.0921	$1.42	$48,000

Data source: *ACIL Tasman's* PowerMark *generator data base*

2.4.2 Fuel Prices

Fuel prices assumed for the Queensland generators is shown in Table 2

Table 2 **Fuel prices assumed for Queensland power stations (nominal $/GJ)**

Generator	Fuel	2012	2013
Barcaldine	Natural gas	$6.96	$7.11
Braemar 1	Natural gas	$2.80	$2.87
Braemar 2	Natural gas	$3.04	$3.11
Callide B	Black coal	$1.41	$1.44
Callide C	Black coal	$1.41	$1.44
Collinsville	Black coal	$2.25	$2.30
Condamine	Natural gas	$1.78	$2.22
Darling Downs	Natural gas	$3.96	$4.27
Gladstone	Black coal	$1.67	$1.71
Kogan Creek	Black coal	$0.80	$0.82
Mackay GT	Liquid Fuel	$32.27	$33.07
Millmerran	Black coal	$0.91	$0.93
Mt Stuart	Liquid Fuel	$32.27	$33.07
Oakey	Natural gas	$4.43	$4.53
Roma	Natural gas	$5.18	$5.66
Stanwell	Black coal	$1.49	$1.53
Swanbank E	Natural gas	$3.64	$3.80
Tarong	Black coal	$1.08	$1.10
Tarong North	Black coal	$1.08	$1.10
Townsville	Natural gas	$4.24	$4.33
Yarwun	Natural gas	$3.73	$3.80

Data source: ACIL Tasman research based on a wide variety of data sources and fuel market modelling

2.4.1 Plant outages

Planned and forced outages assumed for the Queensland plant are shown in Table 3.

Table 3 **Planned and forced outages for Queensland power stations**

Power station	Planned outage		Forced outage rate		Availability	
	2012	2013	2012	2013	2012	2013
Barcaldine	0.0%	8.2%	2.5%	2.5%	98%	89%
Barron Gorge	4.1%	4.1%	1.8%	1.8%	94%	94%
Braemar 1	0.0%	5.3%	1.3%	1.3%	99%	93%
Braemar 2	2.6%	0.0%	0.5%	0.5%	97%	100%
Callide B	7.7%	0.0%	4.2%	4.2%	88%	96%
Collinsville	1.6%	3.3%	3.9%	3.9%	94%	93%
Callide C	5.2%	5.2%	6.9%	6.9%	88%	88%
Condamine	3.6%	3.6%	1.4%	1.4%	95%	95%
Darling Downs	0.0%	8.2%	3.2%	3.2%	97%	89%
Gladstone	4.1%	4.1%	4.0%	4.0%	92%	92%
Kareeya	2.1%	2.1%	1.9%	1.9%	96%	96%
Kogan Creek	0.0%	8.2%	4.4%	4.4%	96%	87%
Millmerran	4.1%	4.1%	6.0%	6.0%	90%	90%
Mt Stuart	0.0%	5.3%	2.4%	2.4%	98%	92%
Stanwell	2.1%	2.1%	2.6%	2.6%	95%	95%
Swanbank B	4.0%	4.0%	6.9%	6.9%	89%	89%
Swanbank E	8.2%	0.0%	3.1%	3.1%	89%	97%
Tarong	2.0%	2.0%	3.0%	3.0%	95%	95%
Tarong North	0.0%	7.9%	2.9%	2.9%	97%	89%
Townsville	8.2%	0.0%	3.0%	3.0%	89%	97%
Yarwun	0.0%	8.2%	2.9%	2.9%	97%	89%

Data source: ACIL Tasman research based on a wide variety of data sources including AEMO

2.4.2 Load data

As outlined in its Methodology Report, ACIL Tasman uses a number of data sources to estimate the price distribution for the settlement classes applying in the Energex and Ergon Energy areas.

The data sources include:

- Half hour load traces for each NEM region for the four years 2007/08 to 2010/11 published by the Australian Energy Market Operator (AEMO)on its website, used in the pool price modelling
- Half hour load traces for each Transmission Node Identity (TNI) for Energex area from AEMO via the Authority to provide an overall load trace for Energex
- Net System Load Profile (NSLP) for Energex for the four years 2007/08 to 2010/11 from the AEMO website to be used for estimation of costs for customers <100MWh per annum and Ergon Energy NSLP to be used for customers >100MWh per annum in the Ergon Energy area. Use of the NSLP to estimate wholesale EPC for large Ergon Energy customers was based on advice from Ergon Energy that large customers (SAC, CAC and ICC) on regulated tariffs in its area were included in the NSLP and thus the wholesale EPC for these customers should be based on the NSLP.
- Controlled load traces from the AEMO website for use in estimating the cost of supplying these tariffs

- Actual interval meter data for Energex area customers 2010/11 and estimates for the three years 2007/08 to 2009/10 to establish load traces for the various commercial and industrial tariffs
- 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
- Load forecast of summer and winter peak demands and annual energy for each NEM region published by AEMO in its 2011 Electricity Statement of Opportunities (ESOO) to be used as a basis for estimating the load trace for 2012/13 for all regions except Queensland
- Load forecast of summer and winter peak demands and annual energy for Queensland published by Powerlink in its Updated 2011 Annual Planning report (APR) used as a basis for estimating the load trace for 2012/13 for Queensland

2.4.3 Other data

In addition to load and generator data the following are required:

- 40 years of three hourly temperature data for capital cities to be used in selecting the40 years of load traces used in the pool price modelling
- Proprietary information on prospective renewable energy developments including their type, location, capacity and costs for use in ACIL Tasman's *RECMark* to determine renewable energy capacity to be used in the 2012/13 pool price modelling.

2.5 The price distribution methodology in detail

2.5.1 Step 1: Estimate load traces for four years

To enable the estimation of the various load traces the following extracted and or estimated data is used:

- Net System Load Profile (NSLP) for Energex from the AEMO website for the four years 2007/08 to 2010/11
- controlled load traces from the AEMO website for the four years 2007/08 to 2010/11 for the Energex area
- interval meter data for Energex area customers for 2010/11 to establish load traces for the SAC, CAC and ICC and tariffs. The 2010/11 profiles have been used to establish similar load profiles for the years 2007/08 to 2009/10 by adjusting the 2010/11 profiles to match annual consumption data and the load profile found by subtracting the NSLP and control load profiles from the overall Energex load
- 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

- Net System Load Profile (NSLP) for Ergon Energy from the AEMO website for the four years 2007/08 to 2010/11.

These data sources enable the estimation of the required retail tariff load traces.

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

Development of 41 annual load traces for the total of NEM region and associated settlement classes in the Energex and Ergon Energy areas 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 settlement classes in the Energex and Ergon Energy areas the four years 2007/08 to 2010/11. Under this approach each day in each of the 41 years would be populated by load traces selected from four years of actual data set of the same day type and season with the closest matching temperature conditions. The three years of data 2007/08 to 2009/10 is uplifted to the 2010/11 level by applying a percentage growth per quarter.

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 four years of load data from 2007/08 to 2010/11 across all NEM regions. Once the day with the same day type and season in four years from 2007/08 to 2010/ that best matches the temperature profile of the day in question is identified, then all the associated NEM regional and settlement classes in the Energex and Ergon Energy areas 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 settlement class load traces in the Energex and Ergon Energy areas.

This procedure produces 41 years of load traces which represent 2010/11 with 37 developed from past temperature data and the actual load traces for the four years 2007/08 to 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 except Queensland. For Queensland the load forecast for 2012/13 from the Updated 2011 APR is used. This involves adjusting the load profiles for the NEM regions to match the 10 percent POE peak demand for 2012/13 across the whole 41 years and to ensure the energy under the 41 years load trace is 41 times the annual forecast for 2012/13.

The matching 41 years of load traces for Energex total, Energex NSLP and the individual tariff load traces are also adjusted by the same amounts to provide consistent load traces to represent 2012/13.

2.5.3 Step 3: Develop 10 plant outage scenarios for 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. 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 10 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.

2.5.4 Step 4: Estimate pool prices across the 410 data years

The 41 years of load data adjusted to 2012/13 levels and 10 outage scenarios are combined to create 410 years of data for input to *PowerMark* to produce 410 years of hourly prices representing 2012/13. These 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 (Queensland reference node).

2.5.5 Step 5: Estimate the annual average load weighted price for each retail tariff

This step involves calculating 410 annual average load weighted prices by using the hourly loads traces adjusted to 2012/13 levels from Step 2 and Queensland hourly prices from Step 4. This process is repeated for the NSLP and each of the new retail tariffs in the Energex area using the Queensland pool price from Step 4 and the retail tariff load traces from Step 2.

This process produces 410 annual average load weighted pool prices for the NSLP and each of the new retail tariffs to form a price distribution for each retail tariff in the Energex area for 2012/13.

2.5.6 Step 6: Find the mean of the price distribution and apply a transmission and distribution loss factor

The mean of each of the price distributions established in Step 5 represent the price at the Queensland reference node. To bring these retail tariff prices from the Queensland regional reference node to the customer terminals a distribution loss factor (DLF) for Energex and Ergon Energy east zone and load weighted Marginal Loss Factor (MLF) are applied for the Energex area and the Ergon Energy east zone to allow for transmission losses from the reference node.

The transmission loss factor for the Energex and Ergon Energy's east zone area is based on the average energy-weighted marginal loss factor for the Energex and Ergon Energy east zone TNI's. This analysis resulted in a loss factor of 0.98 percent for Energex and 4.61 percent for the Ergon Energy east zone.

The distribution loss factor by tariff in the Energex area and the Ergon Energy east zone are taken from the AEMO Distribution Loss factors for 2011/12. The estimated transmission and distribution loss factors for the tariffs and tariff groups in the Energex area are shown in Table 4.

Table 4 **Estimated transmission and distribution loss factors for Energex and Ergon Energy's east zone**

Tariff or tariff group	Distribution losses	Transmission losses	Total losses
NSLP - residential and small business	6.3%	1.0%	7.4%
Control tariff 9000	6.4%	1.0%	7.5%
Control tariff 9100	6.4%	1.0%	7.5%
ICC customers	1.6%	1.0%	2.6%
CAC customers large	1.2%	1.0%	2.2%
CAC customers balance	2.1%	1.0%	3.1%
SAC HV demand customers	2.4%	1.0%	3.4%
SAC customers balance	2.8%	1.0%	3.8%
Un-metered supply	6.4%	1.0%	7.5%
Ergon NSLP - ICC, CAC and SAC	3.6%	4.2%	8.0%

Data source: ACIL Tasman analysis on each of the Queensland TNIs, Queensland MLFs add Energex and Ergon Energy DLFs all from AEMO.

2.5.7 Step 7: Consider adding a risk premium

As discussed in the November 2011 Methodology Report the factors which are likely to influence energy purchase costs include:

- counterparties to hedge contracts may have different risk profiles and risk appetites, meaning that they may be prepared to pay more or less than the mean of the price distribution. Assuming the retailer is more risk averse than the generators, then the equilibrium contract price will be above the mean of the price distribution but if the reverse were true than the contract equilibrium price can be expected to be less than the mean of the price distribution. ACIL Tasman has no information quantify this factor and has therefore made no allowance for it in the EPC estimate.
- 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 other than the introduction of a tax on CO_2 emissions from July 2012.

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 is assumed that this aspect will not impact contract costs for 2012/13.ACIL Tasman has been unable to quantify the likely size of this risk premium with any certainty and has made no allowance for it in the wholesale EPC estimate from the price distribution. This approach is supported by the fact that the contract hedge results for 2012/13 presented in Section 3 are generally lower than the mean of the price distribution suggesting there is there is no risk premium over the mean of the price distribution.

The generally lower prices from the hedge modelling may be as a result of an oversupplied market where generators face higher price risks. This result runs counter to ACIL Tasman's view that a risk premium would normally be added to the mean of the price distribution to account for the generally higher price risk faced by retailers which, to manage this risk, would be prepared to pay a premium above the mean price.

The results from the two methods illustrate the difficulty in estimating a risk premium, which is the key reason why ACIL Tasman favours using the hedging approach discussed in Section 3 for all settlement classes, apart from the control and un-metered tariffs.

2.5.8 Step 8: Add an allowance for time value of pre-purchasing contracts

Contracts with longer tenor or acquired well in advance of the period to which they apply would be expected to have an additional premium in the price (price would be expected to be higher). This additional premium can be thought of as the time value of the option and is normally represented by theta (□) in the theory of pricing options. The longer the time to expiry of the option, the greater the chance that it will payout and the higher the potential payout (there is more time for prices to rise or fall). In one sense the time value reflects the additional cost of paying to remove risk and uncertainty earlier rather than later.

When retailers purchase swap or future contracts (which would be expected to make up the vast bulk of their contract portfolio), they are in effect purchasing a call option on the pool price in each half hour to which it applies which pays-off when pool prices rise (cap) and selling a put option on the pool price in each half hour to which it applies (floor) which they must make payments against when pool prices fall, with the strike price in the cap and floor being the same. To confirm this relationship, a swap or futures contract with the same strike price as the combined cap/floor structure has exactly the same pay-off as the combined cap and floor structure - i.e. the retailer makes payments when the pool price is below the strike price and receives payments when the pool price is above the strike price.

Both the call and put have inherent time value and to some extent the time value premium in the purchased cap would be expected to be offset by the time value premium in the sold floor. However, as rises and falls in pool prices are asymmetric, the time value premium of the cap would be expected to be greater than the time value premium of the floor in the combined cap/floor structure used to replicate a swap or future contract.

This underlying time value is reflected in the expectation that the contract strike price will be higher when the contract is purchased further in advance of the specific period to which it applies. As retailers purchase contracts on a portfolio basis over time, with some contracts purchased well in advance of the year or quarter to which they apply, making allowance for contract prices to be higher associated with earlier purchases in time would appear justified. A proposed approach for quantifying this is discussed below.

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

It should be noted that this time value concept is entirely separate to the concept of time value of money, which relates to use of funds today compared with use in the future.

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 5 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 5 **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

2.6 Review of methodology

One of the main concerns with the approach reported by stakeholders responding to ACIL Tasman's November 2011 Methodology Report was its lack of transparency in that it relies on extensive data manipulation and market modelling using propriety software to estimate the hourly pool prices. However, the necessary input data are available and the approach is based on reasonable theoretical foundations. Furthermore, the alternative of using a contract hedging approach still has the disadvantage of a thinly traded market for the first half of 2013 and the ensuing contract price uncertainty.

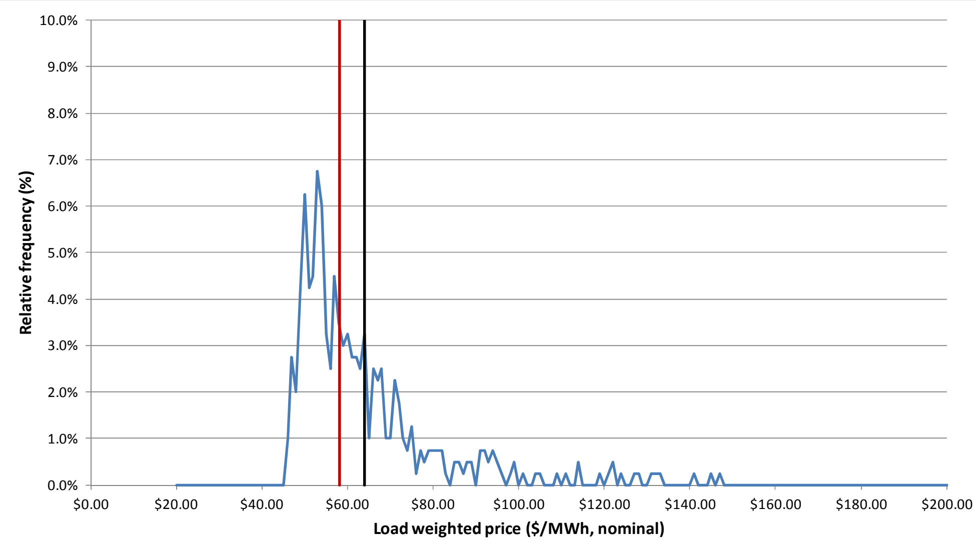
The approach developed and used by ACIL Tasman to evaluate energy costs for industry participants for many years has been significantly enhanced for this exercise by including the modelling of pool prices for the whole of the 410 years being analysed, thereby avoiding the need to use econometric relationships to determine prices for all but one year. ACIL Tasman is of the opinion that, provided the input assumptions are sound, the approach provides a reasonable estimate of a likely range of energy purchase costs in the absence of risk management.

That said, an inability to estimate the risk premium as outlined in Step 7 with any surety present drawback for the methodology.

2.7 Results of the price distribution approach.

The price distribution of the 410 annual average load weighted prices for the Energex NSLP load profile to apply to the residential and small business tariffs in 2012/13 is shown in Figure 1. It clearly shows the skewed nature of the price distribution, which results in the median (red line) being lower than the mean (black line).

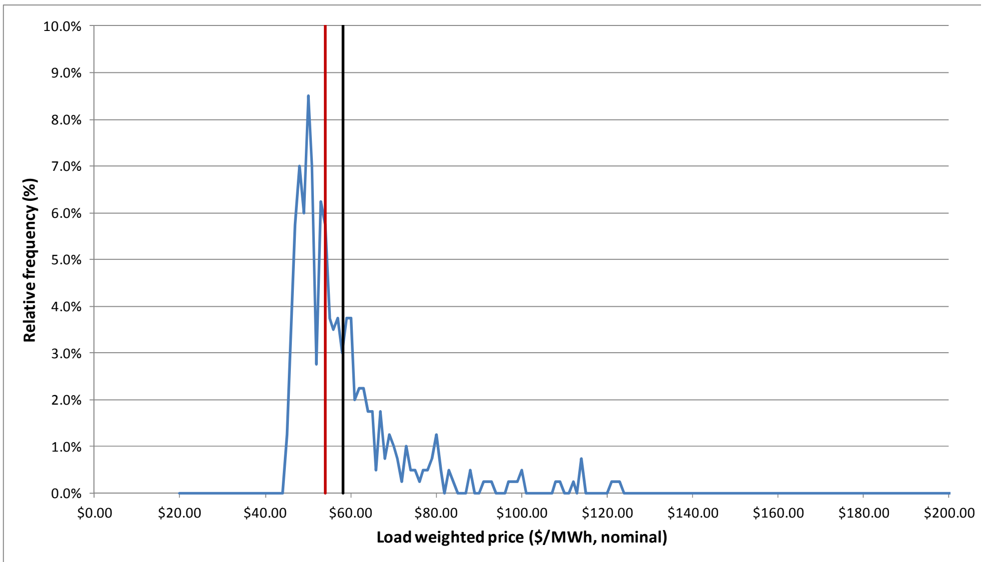
Figure 1 **Price distribution for the Energex NSLP for 2012/13 (MWh)**



Source: ACIL Tasman modelling and analysis

The price distribution of the 410 annual average load weighted prices for the Ergon Energy NSLP load profile to apply to the ICC, CAC and SAC customers in 2012/13 is shown in Figure 2. The mean price to supply the Ergon Energy NSLP is lower than the mean price to supply the Energex NSLP. The main reason is because the Ergon Energy NSLP is a flatter profile because of the dispersion of the Ergon Energy load and because it includes a number of large industrial customers.

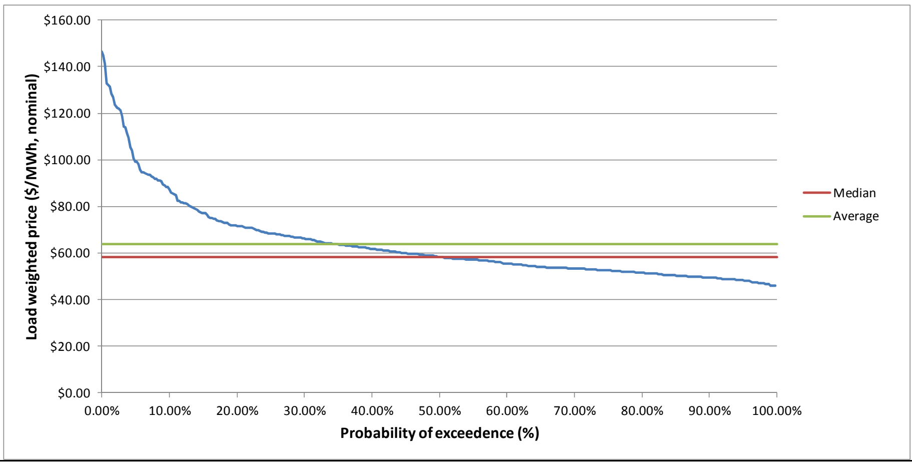
Figure 2 **Price distribution for the Ergon Energy NSLP for 2012/13 ($/MWh at the Queensland reference node)**



Source: ACIL Tasman modelling and analysis

Figure 3 is based on the same data for the Energex NSLP shown in Figure 1 arranged to give the probability of exceedence of the 410 prices from the distribution. It shows that the mean price of $63.97/MWh occurs at the 66th percentile of the price distribution, meaning that there is a 34 percent chance that the mean price will be exceeded. It also shows, for example, that there is a 5 percent chance that the price could be above $99.20/MWh.

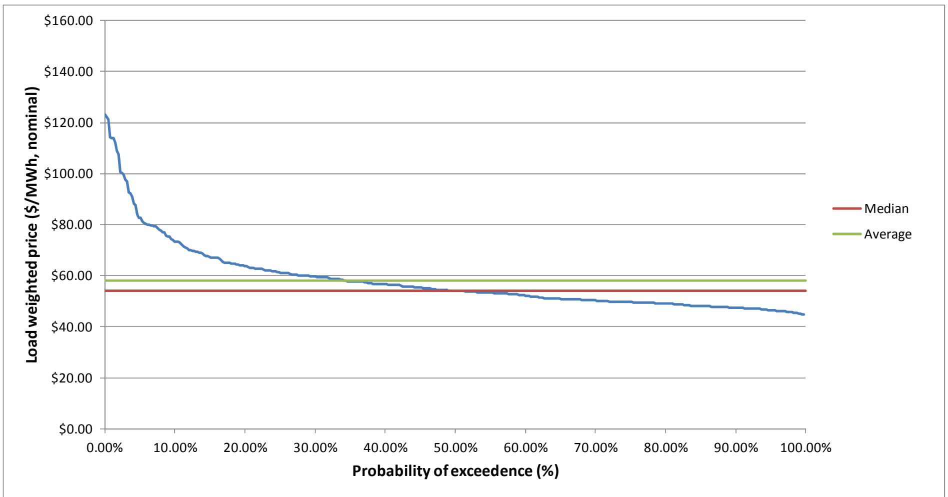
Figure 3 **Probability of exceedence of each of the 410 prices for Energex NSLP for 2012/13 ($/MWh at the Queensland reference node)**



Source: ACIL Tasman modelling and analysis

Figure 4 is based on the same data for the Ergon Energy NSLP arranged to give the probability of exceedence of the 410 prices from the distribution. The mean of $58.18/MWh also occurs at the 66th percentile of the price distribution meaning there is a 34 percent chance that the mean price will be exceeded.

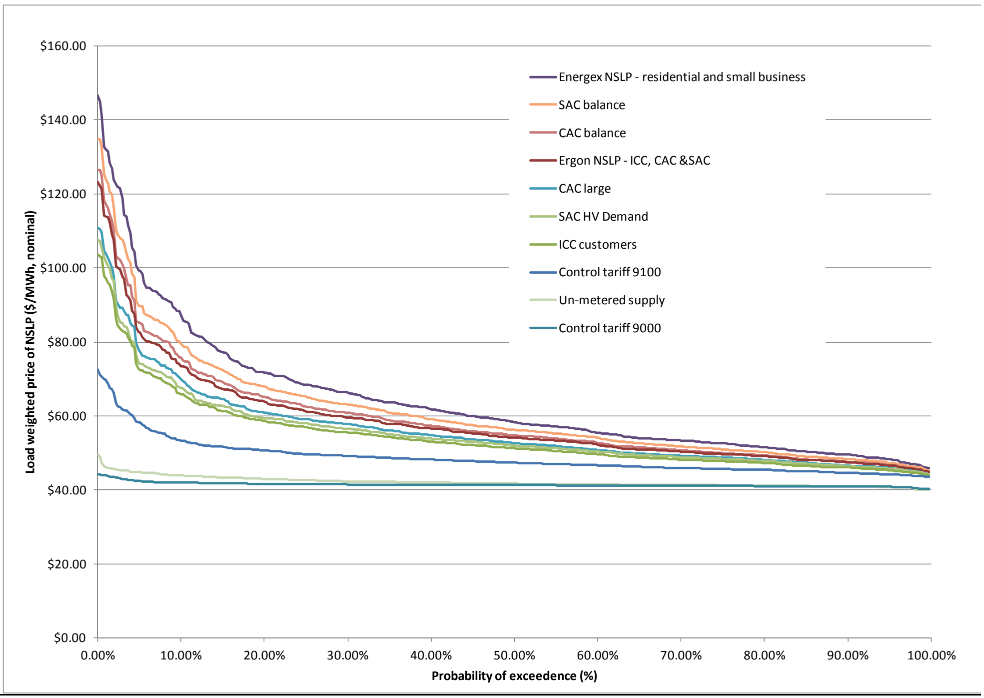
Figure 4 **Probability of exceedence of each of the 410 prices for Ergon Energy NSLP for 2012/13 ($/MWh at the Queensland reference node)**



Source: ACIL Tasman modelling and analysis

Figure 5 shows the data for the 410 annual average load weighted prices for each of the tariffs and tariff groups in the Enegex area and the NSLP for the Ergon Energy area on a probability of exceedence basis. Figure 5 demonstrated the impact on the price distribution of differing load profiles. It shows for example that the control tariffs are flatter and lower that the NSLP for Energex covering residential and small business.

Figure 5 **Probability of exceedence of each of the 410 prices for relevant tariff or tariff group in Energex and Ergon Energy areas for 2012/13 ($/MWh at the Queensland reference node)**



Source: ACIL Tasman modelling and analysis

Table 23 provides the preliminary wholesale energy cost estimates for each relevant tariff or tariff group for the Energex and Ergon Energy area for 2012/13. Allowance for losses and adjustments for the cost of forward purchasing of contracts are all included in the prices presented in the right hand column of the table The costs do not include renewable scheme costs or market fees.

Table 6 **Estimated wholesale energy purchase costs for Energex and Ergon Energy relevant tariffs and groups of tariffs**

Settlement classes	Mean of price distribution at the Queensland reference node	Allowance for transmission and distribution losses	Allowance for time value of pre-purchasing of contracts	Estimated wholesale energy purchase costs at the customer terminal
Prices including carbon pricing				
Queensland total	$57.33	9.4%	1.2%	$63.45
Energex - NSLP - residential and small business	$63.97	7.4%	1.2%	$69.46
Energex - Control tariff 9000	$41.39	7.5%	1.2%	$44.99
Energex - Control tariff 9100	$48.59	7.5%	1.2%	$52.82
Energex - ICC customers	$54.27	2.6%	1.2%	$56.32
Energex - CAC customers large	$56.10	2.2%	1.2%	$57.98
Energex - CAC customers balance	$59.06	3.1%	1.2%	$61.57
Energex - SAC HV demand customers	$55.17	3.4%	1.2%	$57.69
Energex - SAC customers balance	$61.03	3.8%	1.2%	$64.07
Energex - Un-metered supply	$42.10	7.5%	1.2%	$45.76
Ergon Energy - NSLP - ICC, CAC &SAC	$58.18	8.0%	1.2%	$63.55
Prices without carbon pricing based on 87% pass through				
Queensland total	$37.33	9.4%	1.2%	$41.31
Energex - NSLP - residential and small business	$43.97	7.4%	1.2%	$47.75
Energex - Control tariff 9000	$21.39	7.5%	1.2%	$23.25
Energex - Control tariff 9100	$28.59	7.5%	1.2%	$31.08
Energex - ICC customers	$34.27	2.6%	1.2%	$35.57
Energex - CAC customers large	$36.10	2.2%	1.2%	$37.31
Energex - CAC customers balance	$39.05	3.1%	1.2%	$40.72
Energex - SAC HV demand customers	$35.17	3.4%	1.2%	$36.77
Energex - SAC customers balance	$41.03	3.8%	1.2%	$43.08
Energex - Un-metered supply	$22.10	7.5%	1.2%	$24.02
Ergon Energy - NSLP - ICC, CAC &SAC	$38.17	8.0%	1.2%	$41.70

Note: *Prices without carbon do not include the assumed 87% pass through of the average carbon price of \$23.00/tCO2-e for 2012/13 included in the prices with carbon. The 87 percent pass through means that 87 percent of the carbon price in \$/tCO2-e is passes through to the electricity price in \$/MWh. This is based on a NEM emissions factor of 0.87tCO2-e/MWh.*

Data source: ACIL Tasman modelling and analysis

3 Hedging approach to estimating the wholesale EPC

3.1 Methodology

The hedging approach is presented as an alternative to the price distribution approach. The hedging approach is a market based approach used to estimate wholesale energy market costs, not unlike the method used to as part of calculating the BRCI.

The approach is designed to simulate the wholesale energy market from a retailing perspective, where retailers hedge the pool price risk by entering into electricity futures contracts It involves using the 410 years of hourly pool prices and load profiles from the price distribution approach as input to a contracting model to estimate wholesale energy purchase costs. .

The approach is a simplification of the actual contract market in that it is based on base, peak and cap contracts only. It does not include other instruments available to retailers, and about which ACIL does not have sufficient information to use to estimate energy costs, such as purchase of predetermined load profiles and use of own generation. The effects of these simplifications are unknown but we believe the more complex hedging approach followed by retailers is more likely to generally result in lower overall energy purchase costs than the estimates from the simplified contract model.

The hedging approach includes the following steps:

Step 1. Take price and load data from the price distribution approach - Take the hourly prices and load profiles for the 410 years representing possible outcomes for 2012/13 from Step 4 of the price distribution approach.

Step 2. Select the median price year - From the 410 years in Step 1 select the year which delivers the median of the annual average load weighted price.

Step 3. Determine hedging strategy - Determine an appropriate hedging strategy which a prudent representative retailer would use. The hedging strategy involves setting the parameters to calculate the base, peak and cap contract volumes based on the median year.

Step 4. Determine contract volumes - Contract volumes are calculated by applying the hedging strategy to the median year load profile selected in Step 2. These contract volumes are then fixed across all 410 years when calculating the wholesale energy purchase costs.

Step 5. Estimate forward contract prices - Estimate forward quarterly contract prices for base, peak and cap contracts for 2012/13 using forward contract price data from d-cypha Trade

Step 6. Estimate energy purchase costs for each of the 410 years - Bring together the contract prices and volumes for the median price year with the projected half-hourly pool prices for the 410 years in a contract model and calculate a cost of wholesale energy for each of the 410 years.

Step 7. Calculate the energy purchase costs for 2012/13 - Estimated energy purchase costs for 2012/13 are taken as the simple average of the 410 annual energy purchase cost estimates from Step 6

Step 8. Estimate energy purchase costs for each retail tariff or group of tariffs - This is achieved by repeating Step 6 and Step 7 using the same hourly pool prices and contract strategy in Step 1and Step 2 but with load profiles and contract volumes for each settlement class. For tariffs for all customers <100MWh annual consumption (residential and small business) the NSLP profile is used. This means that the estimated energy purchase costs are the same for all of these customers.

3.2 Assessment of contract price data

ACIL Tasman accessed a variety of data sources to estimate the forward contract prices for 2012/13. The following sources of contract prices are examined:

- Electricity base, peak and cap contract data from d-cypha Trade
- Over the counter (OTC) electricity contract data (contracts including and excluding carbon) from broker TFS
- An extract of broker ICAP contract data for OTC electricity contracts excluding carbon, provided by Origin and Stanwell

A key step in the hedging approach is estimating the quarterly forward contract prices. For the BRCI these prices were based on using electricity base and peak swaps and cap futures data from d-cypha Trade. However, given the thin trading for the first two quarters of 2013 there is some doubt whether the prices from this source provide reasonable contract price estimates.

In submissions to the draft methodology paper, AGL and Origin stated that there is insufficient liquidity in 2012/13 market contracts. ACIL Tasman agrees that the futures market is relatively illiquid – but only for 2013. Analysis of d-cypha Trade data shows that Q3 2012 and Q4 2012 contracts have been sufficiently traded, but that Q1 2013 and Q2 2013 contracts are somewhat thinly traded. Consequently, estimates of contract prices for 2012/13 are based on these low volumes but this is counteracted to an extent by using a trade weighted average price rather than a simple average of contract prices. Also, more contract price data will become available between the draft and final decisions, which is expected to firm up the estimate for the final decision.

Table 7 compares trade volumes of quarterly d-cypha Trade Queensland base futures in recent years. The shaded rows indicate the quarterly contracts that would be used in calculating contract prices for 2012/13.

Table 7 **Trade volume of quarterly Qld base futures - d-cypha Trade**

	Contract quarter	Trade volume [a] (MW)
Q3	Q3 2012	7,325
	Q3 2011	7,216
	Q3 2010	4,181
Q4	Q4 2012	7,449
	Q4 2011	6,944
	Q4 2010	5,346
Q1	Q1 2013	709
	Q1 2012	3,140
	Q1 2011	3,235
Q2	Q2 2013	364
	Q2 2012	1,971
	Q2 2011	1,690

Note: Trade volumes for Q3 and Q4 contracts have been calculated for the period since the contract commenced up until January in the year that the contract expires, i.e. for Q3 2012 the period from October 2008 to January 2012, for Q3 2011 the period from October 2007 to January 2011, etc. Similarly, trade volumes for Q1 and Q2 contracts have been calculated for the period since the contract commenced up until January in the year prior to contract expiry, i.e. for Q1 2013 the period from April 2009 to January 2012, for Q1 2012 the period from April 2008 to January 2011, etc.
Data source: ACIL Tasman analysis of d-cypha Trade data.

Table 7 shows that Q3 2012 base futures (7,325 MW) have traded at levels that are similar to or greater than Q3 2011 futures (7,216 MW) and Q3 2010 futures (4,181 MW). In the same way, Q4 2012 base futures (7,449 MW) have traded at levels that are similar to or greater than Q4 2011 contracts (6,944 MW) and Q4 2010 (5,346 MW).

For this reason, Q3 2012 and Q4 2012 futures have been sufficiently traded and are suitable for use in calculating the average market contract price.

In contrast, trade volumes for Q1 2013 futures (709 MW) and Q2 2013 futures (364 MW) are around one-fifth of the trade volumes of the equivalent quarterly contracts in previous years – Q1 2012 (3,140 MW), Q1 2011 (3,235 MW) and Q2 2012 (1,971 MW), Q2 2011 (1,690 MW).

The less liquid futures market for Q1 2013 and Q2 2013 contracts means that the contract price estimates for these periods can be expected to be less reliable than periods where trading volumes have been higher.

Note, that the trade volumes were calculated over a comparable period, see Table 7 footnote for further details.

3.2.1 Broker data

In submissions to the draft methodology, QEnergy suggested that data from a broker be used to provide an independent forward curve to calculate average contract prices, as an alternative to d-cypha Trade. Others, including Stanwell, Alinta Energy and Ergon Energy, suggested that data from brokers be used as a market source for the hedging approach.

ACIL Tasman purchased two calendar years of trade data from broker Tradition Financial Service (TFS) in order to examine the forward prices of over-the-counter (OTC) contracts and compare with d-cypha Trade data.

In addition, Origin and Stanwell have shared with QCA and ACIL Tasman an extract of data from the broker, ICAP. On comparison with the equivalent TFS data, prices were almost identical.

TFS provides brokerage for all retailers and generators in the market.

For these reasons, the TFS data is a good representation of OTC electricity forward contracts in the market.

Table 8 compares trade-weighted prices and trade volumes of TFS Queensland base OTC contracts with d-cypha Trade Queensland base futures.

Prices are trade-weighted to reflect the average traded contract price in the market.

Table 8 **Comparison of d-cypha Trade and TFS base contracts – trade-weighted price and trade volume**

	d-cypha Trade base (ET) a		TFS base including carbon (OTC) b		TFS base excluding carbon (OTC) b	
	Trade-weighted price ($/MWh)	Volume traded (MW)	Trade-weighted price ($/MWh)	Volume traded (MW)	Trade-weighted price ($/MWh)	Volume traded (MW)
Q3 2012	$41.42	7,325	$42.29	1,604	$30.80	10
Q4 2012	$43.97	7,449	$42.89	1,793	$33.80	10
Q1 2013	$66.89	709	$68.09	190	no trades	no trades
Q2 2013	$49.16	364	$50.28	75	no trades	no trades
Jul-Dec 2012			$52.25	25	$31.95	165
FY 2013			no trades	no trades	$36.45	180
Cal 2013			$52.84	234	$36.75	855

a includes data over the period since trades started to occur (i.e. mid 2009 for 2012 quarters, and Feb 2011 for 2013 quarters) to January 2012

b includes data from January 2010 to January 2012

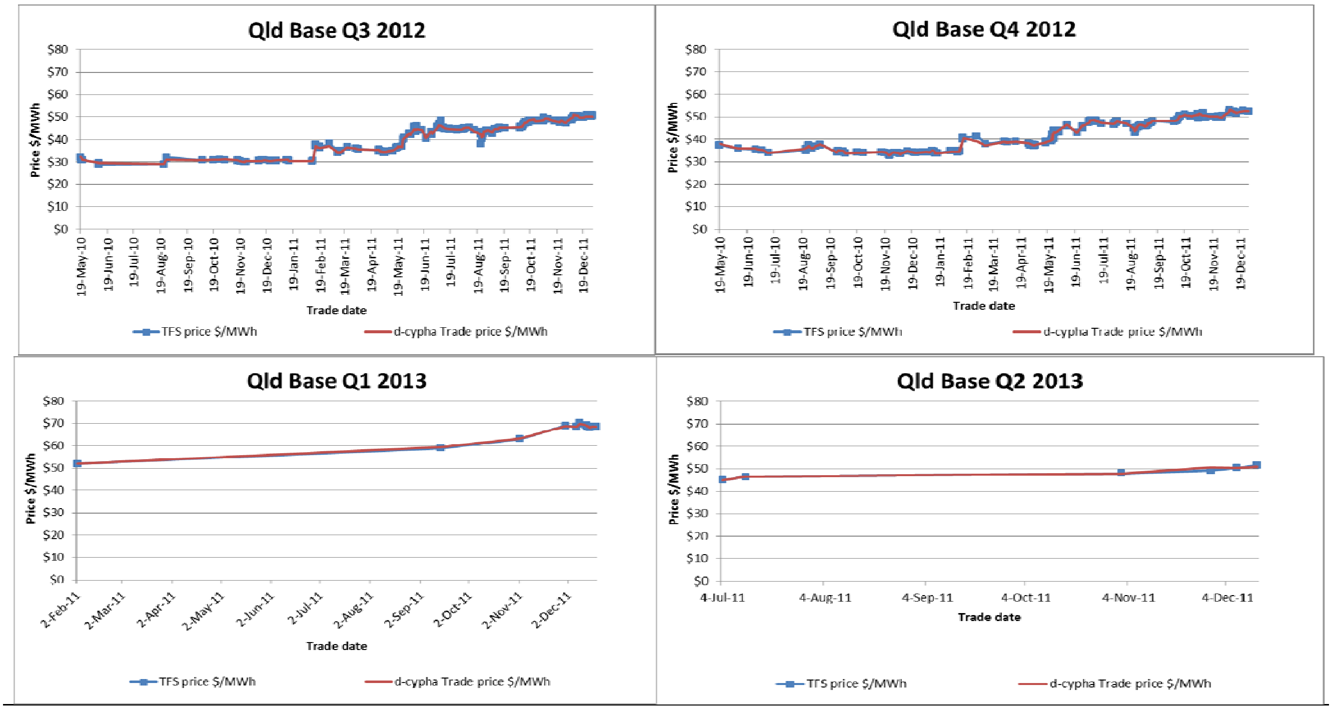
Note: ET = exchange-traded; OTC = over-the-counter;

Data source: ACIL Tasman analysis of d-cypha Trade and TFS data.

Table 8 shows that d-cypha Trade and TFS base including carbon trade-weighted prices are not significantly different.

Similarly, Figure 6 shows that d-cypha Trade base prices for Queensland are almost identical to TFS prices.

Figure 6 **Price comparison of d-cypha Trade base and TFS base including carbon**



Note: Compares d-cypha Trade prices with TFS prices on the dates that the TFS trades occurred.
Data source: ACIL Tasman analysis of d-cypha Trade and TFS data.

The third column in Table 8 shows TFS contracts *excluding* carbon. These contracts are commonly referred to as 'with AFMA'[4] contracts or 'carbon pass-through' contracts. They are simply a contract for electricity with a provision to pass-through the carbon price. In essence, the carbon price is excluded from this price.

In submissions on the Draft Methodology paper, various stakeholders including Alinta Energy and Stanwell suggested that contract prices excluding carbon be used in the hedging approach.

Table 8 shows that TFS 2012 quarterly contracts excluding carbon have traded thinly Q3 2012 (10 MW) and Q4 2012 (10 MW) compared to TFS contracts including carbon Q3 2012 (1,604 MW) and Q4 2012 (1,793 MW).

[4] 'With AFMA' relates to the AFMA Carbon Benchmark Addendum that is attached to contracts, which allows parties to pass through the cost of carbon at the average NEM emissions intensity.

On the other hand, 2013 calendar year contracts excluding carbon have traded relatively strongly (855 MW) compared to d-cypha Trade Q1 2013 (709 MW) and Q2 2013 (364 MW), and TFS contracts including carbon for Q1 2013 (190 MW) and Q2 2013 (75 MW). There were no trades of 2013 quarterly contracts excluding carbon.

For the reasons given above, there is insufficient trading to support using carbon pass-through contract prices for Q3 2012 and Q4 2012.

Although the 2013 calendar year contracts have traded relatively strongly, the difficulty is in ascertaining pass-through contract prices for Q1 2013 and Q2 2013.

3.2.2 Carbon pass-through

Figure 7 is a time series of Queensland base contract prices from d-cypha Trade and TFS (excluding carbon) for calendar year 2013. The blue line represents the TFS excluding carbon contract price that is increased by the amount of the carbon price pass-through. The carbon price pass-through was estimated using the following formula:[5]

CA = ACI*CRP

Where CA is the amount of the increase applied to the 'excluding carbon' contract price;

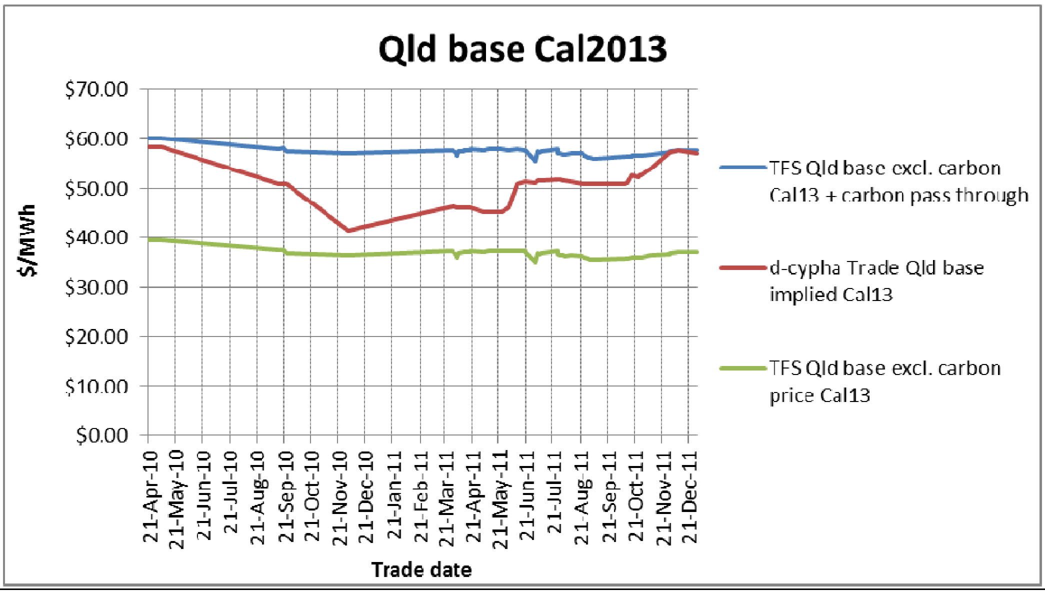
ACI is the average NEM carbon intensity (tCO_2-e/MWh);

CRP is a carbon reference price ($/$tCO_2$-e).

In Figure 7, ACI = 0.8696 (projected average NEM emissions intensity for calendar year 2013 from ACIL Tasman PowerMark modelling), CRP = $23.58 being the average carbon price for the 2013 calendar year (average of $23 and $24.15, being the legislated carbon tax rates for 2012/13 and 2013/14, respectively) and therefore, CA = $20.50.

[5] Australian Carbon Benchmark Addendum, AFMA, August 2010

Figure 7 **Time series comparison of contract prices for Calendar 2013 base contracts – TFS excl. carbon & d-cypha Trade**



Note: d-cypha Trade Qld base price for calendar year 2013 is implied from quarterly contract prices

Data source: ACIL Tasman analysis based on TFS and d-cypha Trade data

Figure 7 demonstrates how the futures market has priced the carbon price component in d-cypha Trade 2013 futures over time.

The step change in June 2011, occurring when the Government announced details on the timing and level of carbon tax, reflects an increase in probability, although still less than 100 percent, that a carbon price would be in place in 2013, while from November 2011, when the carbon tax legislation passed the Senate, the red line meets the blue line, indicating that the futures market has factored in a 100 percent probability of a carbon price in 2013.

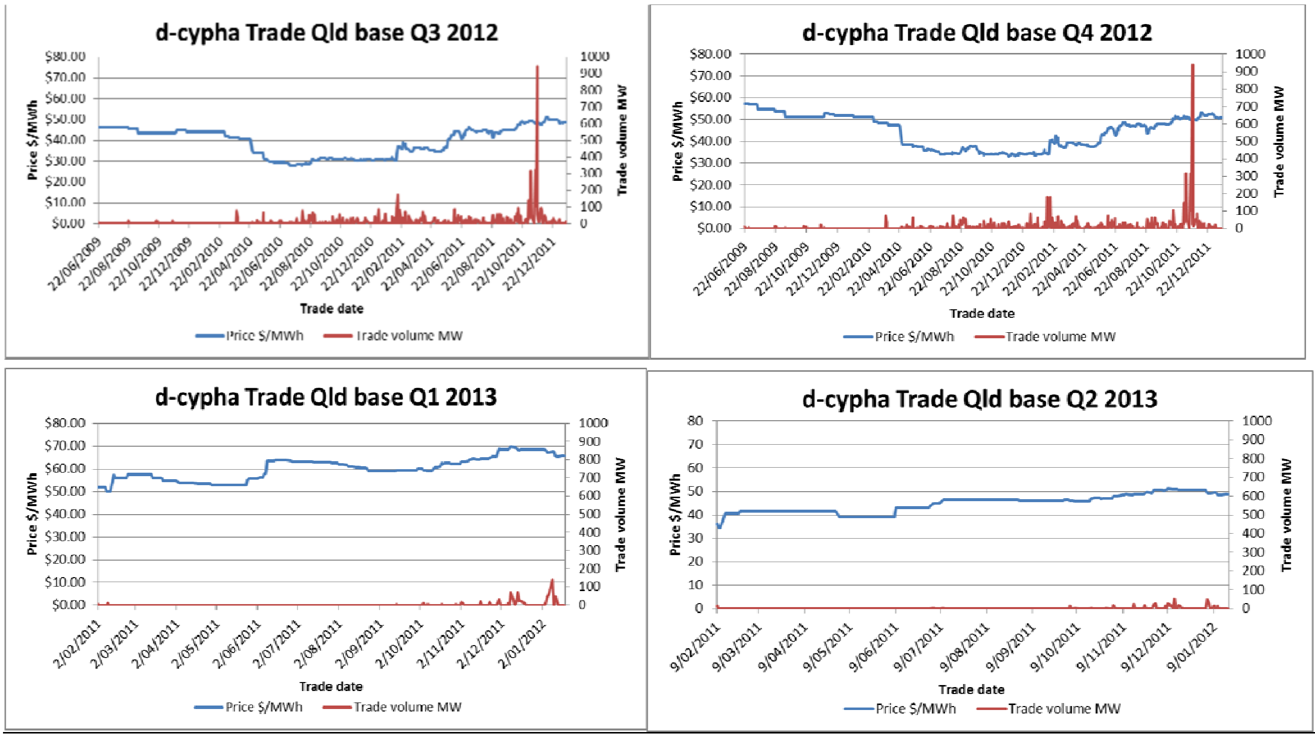
It is highly unlikely that the carbon tax legislation will be repealed before the end of the 2012/13 period. Hence, we expect that the market will factor the full carbon tax (passed through at average NEM intensity) in the current price for 2013 futures.

3.2.3 Hedging timeframe

In its submission to the draft methodology, QEnergy supports the use of three years of data for the hedging approach. Origin supports the use of a six month horizon with data sourced as previously (eg. d-cypha), while the preceding 18 months will need to be constructed from a different source. Ergon Energy suggests calculating the price of contracts since 28 April 2010, while Stanwell supports the use of market prices over the period from 1 July 2011.

For this analysis, ACIL Tasman has calculated the trade-weighted average price of d-cypha Trade contracts since the contracts began trading. The trade-weighted method ensures that the average price represents those prices at which contracts were more heavily traded.

Figure 8 **Time series of trade volume and price – d-cypha Trade**

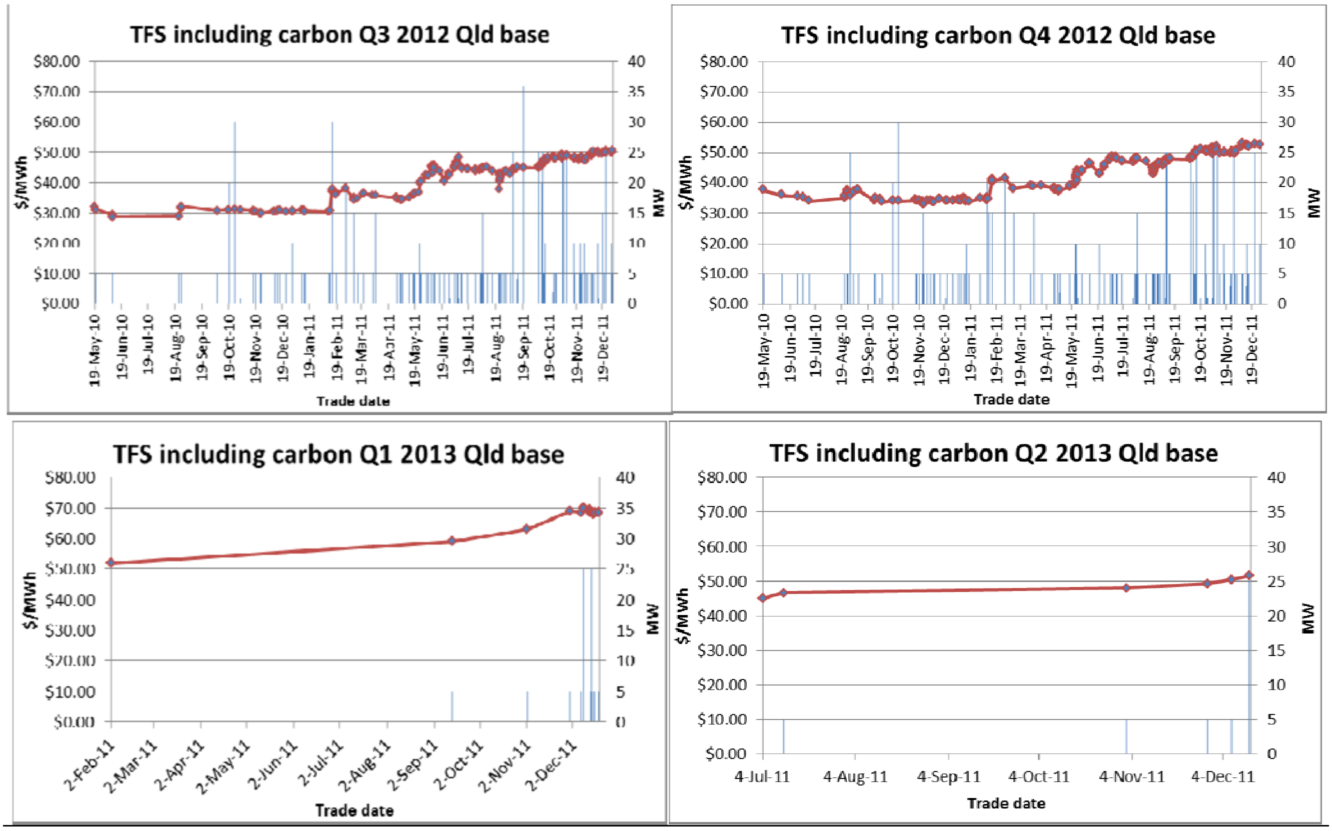


Data source: d-cypha Trade

As shown in Figure 8, Q3 2012 and Q4 2012 contracts began trading in mid-2009, however the majority of trades occurred from mid-2010.

Q1 2013 and Q2 2013 contracts commenced trading in early 2011, although the majority of trades occurred in late 2011 and early 2012.

Figure 9 **Time series of trade volume and price – TFS (including carbon)**

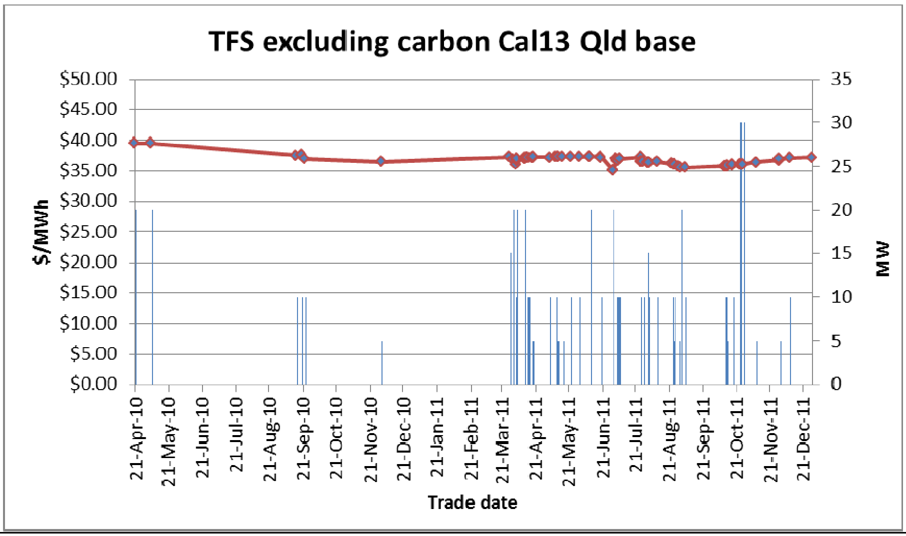


Data source: TFS

The trade-weighted average price of TFS contracts is calculated using data from the broker since January 2010. For 2013 contracts, this is well before they commenced trading.

As shown in Figure 9, the majority of trades for Q3 2012 and Q4 2012 TFS contracts occurred from late-2010, and for Q1 2013 and Q2 2013 TFS contracts most trades occurred from late 2011.

Figure 10 **Time series of trade volume and price – TFS (excluding carbon)**



Data source: TFS

Figure 10 shows that the majority of trades for calendar year 2013 TFS contracts excluding carbon occurred from March 2011.

3.2.4 Peak contracts

Table 9 compares trade volumes of quarterly d-cypha Trade Queensland peak futures in recent years. The shaded rows indicate the quarterly contracts that would be used in the 2012/13 BRCI.

Table 9 **Trade volume of quarterly peak futures - d-cypha Trade**

	Contract quarter	Trade volume (MW)
Q3	Q3 2012	94
	Q3 2011	135
	Q3 2010	45
	Q3 2009	65
Q4	Q4 2012	148
	Q4 2011	188
	Q4 2010	80
	Q4 2009	159
Q1	Q1 2013	45
	Q1 2012	100
	Q1 2011	65
	Q1 2010	30
Q2	Q2 2013	5
	Q2 2012	62
	Q2 2011	0
	Q2 2010	0

[a] Trade volumes for Q3 and Q4 contracts have been calculated for the period since the contract commenced up until January in the year that the contract expires, i.e. for Q3 2012 the period from October 2008 to January 2012, for Q3 2011 the period from October 2007 to January 2011, etc. Similarly, trade volumes for Q1 and Q2 contracts have been calculated for the period since the contract commenced up until January in the year prior to contract expiry, i.e. for Q1 2013 the period from April 2009 to January 2012, for Q1 2012 the period from April 2008 to January 2011, etc.

Data source: ACIL Tasman analysis of d-cypha Trade data.

Table 9 shows that Q3 2012 peak futures (94 MW) have traded at levels slightly lower than Q3 2011 futures (135 MW) but at higher levels than Q3 2010 futures (45 MW) and Q3 2009 futures (65 MW). In the same way, Q4 2012 peak futures (148 MW) have traded at levels slightly lower than Q4 2011 futures (188 MW) but at higher levels than Q4 2010 futures (80 MW) and at similar levels to Q4 2009 futures (159 MW).

Trade volumes for Q3 2012 and Q4 2012 peak futures are not significantly different to contracts for previous years, and therefore are suitable for use in calculating the average market peak contract price.

In contrast, trade volumes for Q1 2013 futures (45 MW) and Q2 2013 futures (5 MW) are a fraction of the trade volumes for Q1 2012 (100 MW), Q2 2012 (62 MW) but are at similar levels or greater than Q1 2011 (65 MW), Q2 2011 (0 MW), Q1 2010 (30 MW) and Q2 2010 (0 MW).

However, the average of trade volumes of the previous years' futures is greater than trade volumes of 2013 futures, and hence, contract prices based on the more thinly traded futures market for Q1 2013 and Q2 2013 can be expected to be less reliable than periods where trading volumes have been higher.

Note, that the trade volumes were calculated over a comparable period, see Table 9 footnote for further details.

Table 10 compares prices and trade volumes of TFS Qld peak OTC contracts with d-cypha Trade Qld peak futures.

Prices are trade-weighted to reflect the average contract price in the market.

There were no trades of peak contracts excluding carbon.

Table 10 **Comparison of d-cypha Trade and TFS peak contracts – trade-weighted price and trade volume**

	d-cypha Trade peak (ET) a		TFS peak including carbon (OTC) b		TFS peak excluding carbon (OTC) b	
	Trade-weighted price ($/MWh)	Volume traded (MW)	Trade-weighted price ($/MWh)	Volume traded (MW)	Trade-weighted price ($/MWh)	Volume traded (MW)
Q3 2012	$42.91	94	$47.46	88	no trades	0
Q4 2012	$53.47	148	$52.69	45	no trades	0
Q1 2013	$96.81	45	$100.50	10	no trades	0
Q2 2013	$60.00	5	$60.00	5	no trades	0

a includes data over the period since trades started to occur (i.e. mid-2010 for 2012 quarters, and mid to late 2011 for 2013 quarters) to January 2012

b includes data from January 2010 to January 2012

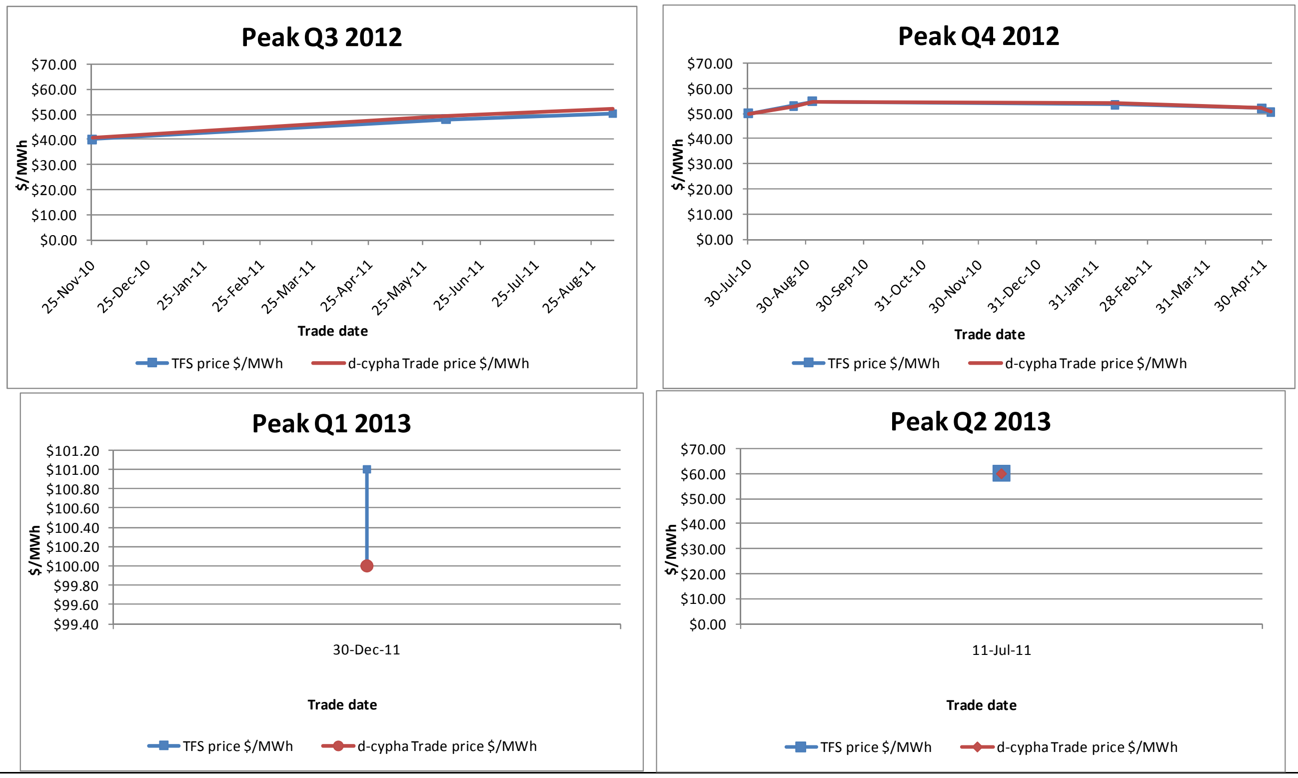
Note: ET = exchange-traded; OTC = over-the-counter;

Data source: ACIL Tasman analysis of d-cypha Trade and TFS data.

The traded weighted prices in Table 10 show that d-cypha Trade peak futures and TFS peak including carbon trade-weighted prices are not significantly different. The difference is due to volume timing differences rather that price differences as shown in Figure 11.

Figure 11 shows that TFS prices are almost identical to d-cypha Trade prices.

Figure 11 **Price comparison of d-cypha Trade peak and TFS peak including carbon**



a

Note: Compares d-cypha Trade prices with TFS prices on the dates that the TFS trades occurred.
Data source: d-cypha Trade and TFS

3.2.5 Cap contracts

Table 11 compares trade volumes of quarterly d-cypha Trade Qld caps in recent years. The shaded rows indicate the quarterly contracts that would be used in the 2012/13 BRCI.

Table 11 **Trade volume of quarterly $300 caps - d-cypha Trade**

	Contract quarter	Trade volume [a] (MW)
Q3	Q3 2012	264
	Q3 2011	303
	Q3 2010	105
Q4	Q4 2012	147
	Q4 2011	116
	Q4 2010	190
Q1	Q1 2013	95
	Q1 2012	0
	Q1 2011	15
Q2	Q2 2013	95
	Q2 2012	0
	Q2 2011	15

[a] Trade volumes for Q3 and Q4 contracts have been calculated for the period since the contract commenced up until January in the year that the contract expires, i.e. for Q3 2012 the period from April 2010 to January 2012, for Q3 2011 the period from April 2009 to January 2011, etc. Similarly, trade volumes for Q1 and Q2 contracts have been calculated for the period since the contract commenced up until January in the year prior to contract expiry, i.e. for Q1 2013 the period from January 2011 to January 2012, for Q1 2012 the period from April 2010 to January 2011, etc.

Data source: ACIL Tasman analysis of d-cypha Trade data.

Table 11 shows that Q3 2012 caps (264 MW) have traded at levels slightly lower than Q3 2011 caps (303 MW) but at higher levels than Q3 2010 caps (105 MW). In the same way, Q4 2012 caps (147 MW) have traded at levels higher than Q4 2011 caps (116 MW) but at slightly lower levels than Q4 2010 contracts (190 MW).

Trade volumes for Q3 2012 and Q4 2012 caps are not significantly different to contracts for previous years, and therefore are suitable for use in calculating the average market cap contract price.

Trade volumes for Q1 2013 caps (95 MW) and Q2 2013 caps (95 MW) are greater than the trade volumes for Q1 2012 (0 MW), Q2 2012 (0 MW), Q1 2011 (15 MW) and Q2 2011 (15 MW).

Trade volumes for Q1 2013 and Q2 2013 are more liquid compared to contracts for previous years, and therefore are considered suitable for use in calculating the average market cap contract price.

Note, that the trade volumes were calculated over a comparable period, see Table 11 footnote for further details.

Table 12 compares prices and trade volumes of TFS Qld cap OTCs with d-cypha Trade Qld caps.

Prices are trade-weighted to reflect the average contract price in the market.

There were no trades of cap contracts excluding carbon, nor were there trades of cap contracts including carbon for Q1 2013 and Q2 2013.

Table 12 **Comparison of d-cypha Trade and TFS $300 cap contracts – trade-weighted price and trade volume**

	d-cypha Trade cap (ET) a		TFS cap including carbon (OTC) b		TFS cap excluding carbon (OTC) b	
	Trade-weighted price ($/MWh)	Volume traded (MW)	Trade-weighted price ($/MWh)	Volume traded (MW)	Trade-weighted price ($/MWh)	Volume traded (MW)
Q3 2012	$3.59	264	$3.82	95	no trades	0
Q4 2012	$6.65	147	$6.64	120	no trades	0
Q1 2013	$14.40	95	no trades	0	no trades	0
Q2 2013	$3.20	95	no trades	0	no trades	0
Cal 2013			$7.18	50	no trades	0

a includes data over the period since trades started to occur (i.e. late-2010 for 2012 quarters, and mid-2011 for 2013 quarters) to January 2012

b includes data from January 2010 to January 2012

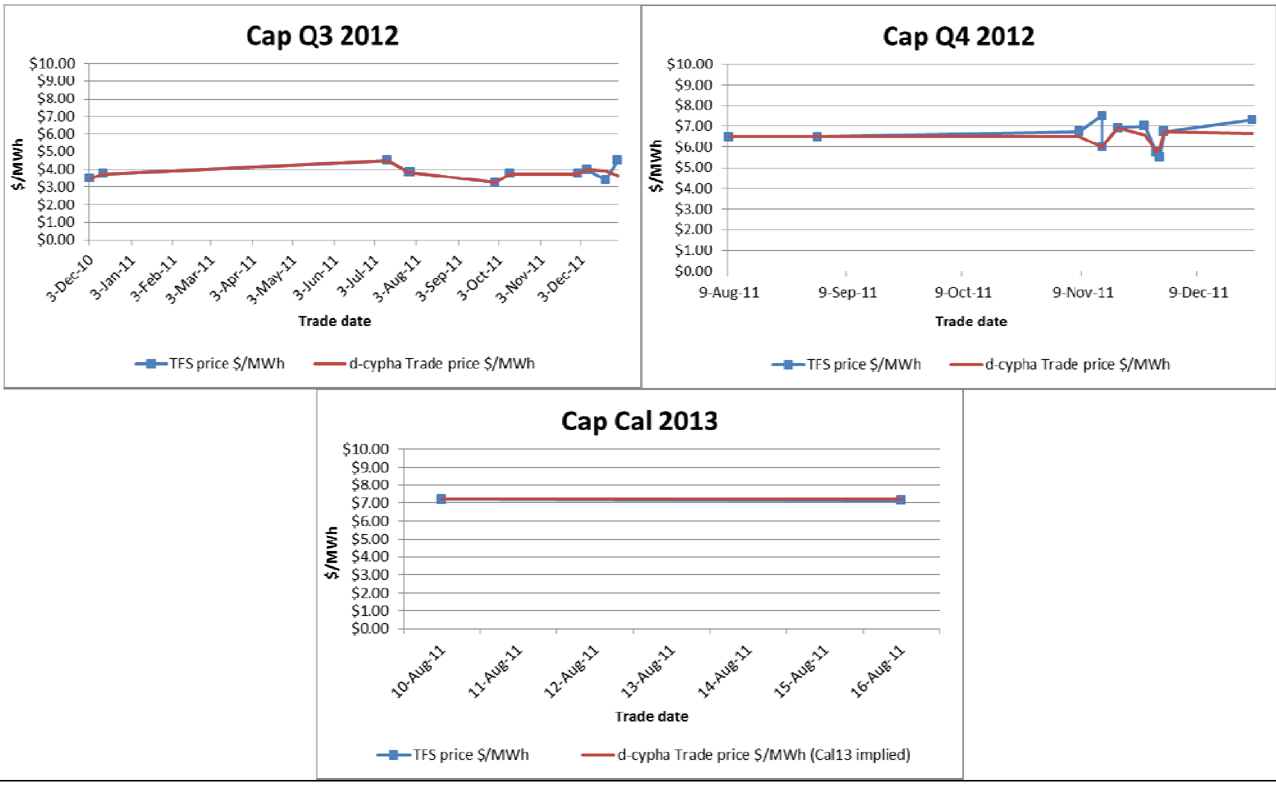
Note: ET = exchange-traded; OTC = over-the-counter;

Data source: ACIL Tasman analysis of d-cypha Trade and TFS data.

The first two columns in Table 12 show that d-cypha Trade caps and TFS caps including carbon trade-weighted prices are not significantly different.

Figure 12 shows that TFS and d-cypha Trade prices plotted on a time scale.

Figure 12 **Price comparison – d-cypha Trade and TFS $300 caps – Q3 2012, Q4 2012 & Cal2013**



a

Note: There were no trades of Q1 2013 and Q2 2013 TFS contracts.

Data source: d-cypha Trade and TFS

3.3 Estimated contract prices used in the hedging approach

Base, peak and cap contract prices for the four quarters of 2012/13 used in the hedging approach have been estimated based on the analysis of d-cypha Trade futures and broker data in Section 3.2 above.

We have concluded that the d-cypha Trade futures market is sufficiently liquid for Q3 2012 and Q4 2012 base, peak and cap contracts as well as for Q1 2013 and Q2 2013 caps.

On this basis ACIL Tasman believes that the d-cypha Trade futures market is a reliable source from which to calculate average contract prices for these contracts.

The cost of Q3 2012 and Q4 2012 base, peak and cap contracts and Q1 2013 and Q2 2013 caps were estimated using the trade-weighted average of daily settlement prices and trades from the date that trading commenced up until 18

January 2012, which is the cut-off date[6] ACIL Tasman has chosen for market data for the Draft Decision on the 2012/13 retail tariff determination..

Prices are trade-weighted to reflect the average contract price in the market, so that prices at which contracts were more heavily traded are given more weighting in the overall estimated contract price. This is particularly important for 2012/13, as most trades have occurred in the last 6-12 months, often at higher prices as the introduction of a carbon tax in Q3 2012 has become increasingly certain.

On the other hand, d-cypha Trade Q1 2013 and Q2 2013 base and peak futures have traded thinly, while contracts excluding carbon for calendar year 2013 have traded relatively well, as shown in Table 8 in Section 3.2.2. The problem is estimating prices of contracts excluding carbon for Q1 2013 and Q2 2013 when there is data for calendar year 2013 only.

An alternative method for estimating Q1 2013 and Q2 2013 base and peak futures is to take the trade-weighted average of d-cypha Trade daily settlement prices and trades from 8 November 2011.[7]

This method is based on the analysis of OTC contracts excluding carbon for calendar year 2013 in Section 3.2.2. As demonstrated in Figure 7, the futures market started to factor in 100 percent probability of a carbon tax in 2013 from 8 November 2011 when the Senate passed the Clean Energy Future (CEF) legislation.

In effect, from 8 November 2011, the 2013 futures price is identical to the price of 2013 OTC contract excluding carbon plus the carbon pass-through (see Figure 7).

This alternative method for estimating Q1 2013 and Q2 2013 base and peak contract prices:

- recognises that 2013 OTC contracts excluding carbon have traded well relative to 2013 futures
- allows us to estimate quarterly contract prices (for Q1 2013 and Q2 2013) using d-cypha Trade data, given that there is no data for quarterly OTC excluding carbon contracts.

It is highly unlikely that the carbon tax legislation will be repealed before the end of the 2012/13 tariff period. Hence, we expect that the market will factor

[6] The cut-off date for market data will extend to 31 March 2011 for the Final Decision.

[7] This method is not used for Peak Q2 2013 futures, which have not traded since 8th November 2011 (the latest trade for both d-cypha Trade and TFS was on 11 July 2011). Until this contract is traded further the July 2011 price is used as the estimate of the contract price.

the full carbon tax (passed through at average NEM intensity) in the price of Q1 2013 and Q2 2013 futures from now on.

Table 13 summarises the data source and method, including the time frame, for estimating quarterly contract prices.

Table 13 **Data source and method of estimating contract price**

	2012/13		
	Base contract price	**Peak contract price**	**Cap contract price**
Q3 2012	Trade-weighted average of d-cypha Trade daily settlement prices and trades since trading commenced (mid-2009)	Trade-weighted average of d-cypha Trade daily settlement prices and trades since trading commenced (mid-2010)	Trade-weighted average of d-cypha Trade daily settlement prices and trades since trading commenced (late-2010)
Q4 2012	Trade-weighted average of d-cypha Trade daily settlement prices and trades since trading commenced (mid-2009)	Trade-weighted average of d-cypha Trade daily settlement prices and trades since trading commenced (mid-2010)	Trade-weighted average of d-cypha Trade daily settlement prices and trades since trading commenced (late-2010)
Q1 2013	Trade-weighted average of d-cypha Trade daily settlement prices and trades since 8 November 2011	Trade-weighted average of d-cypha Trade daily settlement prices and trades since 8 November 2011	Trade-weighted average of d-cypha Trade daily settlement prices and trades since trading commenced (early-2011)
Q2 2013	Trade-weighted average of d-cypha Trade daily settlement prices and trades since 8 November 2011	Latest traded price (11 July 2012) on d-cypha Trade	Trade-weighted average of d-cypha Trade daily settlement prices and trades since trading commenced (early-2011)

Key:

= trade-weighted average of all trades

= trade-weighted average since the Senate passed CEF legislation on 8 Nov 2011

= latest traded price (11 July 2012) as there have been no trades since 8th November 2011

As explained above, Q1 2013 and Q2 2013 base and peak contract futures are thinly traded requiring the use of an alternative method for estimating contract prices for these quarters, as shown in the cells shaded green and blue in Table 13.

Table 14 shows estimated quarterly swap and cap contract prices for the Draft Decision for the 2012/13 Tariffs using the methods summarised in Table 13.

Table 14 **Quarterly base, peak and cap contract prices – 2012/13 Draft Decision ($/MWh)**

	2012/13 Draft Decision		
	Base contract price	Peak contract price	Cap contract price
Q3	$41.42	$42.91	$3.59
Q4	$43.97	$53.47	$6.65
Q1	$67.68	$96.81	$14.40
Q2	$50.03	$60.00	$3.20

Key:

= trade-weighted average covering all trades

= trade-weighted average since the Senate passed CEF legislation on 8 Nov 2011

= latest traded price (11 July 2012) as there have been no trades since 8th November 2011

Data source: ACIL Tasman analysis using d-cyphaTrade data

3.4 Hedging strategy

The hedging strategy is the same as used in the BRCI but ACIL Tasman has calculated the energy purchase cost of the hedging approach for each of the 410 years used in the price distribution approach, mainly to test the stability of the hedging strategy. This method was repeated for each individual tariff load profile, as well as for the overall load profile.

The strategy assumes that the retailer's objective is to purchase contracts that match its load as closely as possible so that its over exposure to the spot market during peak periods and under exposure during off-peak periods are at a manageable levels.

The following criteria are used in the contract model to determine hedge volumes:

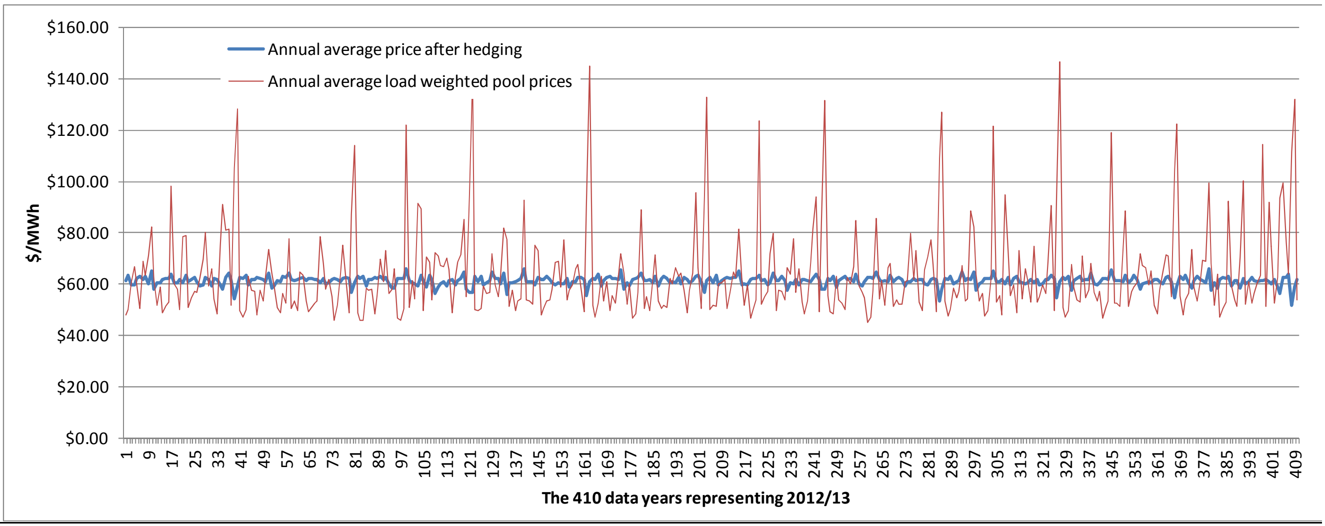
Base swaps	80th percentile of off-peak load
Peak swaps	90th percentile of peak load
$300 caps	105 percent of maximum peak load

The methodology has been discussed with stakeholders and appears to have become broadly agreed.:

In submissions to the draft Methodology Paper, Stanwell and Ergon Energy both agree that the hedge levels used in previous years (i.e. 80th percentile, 90th percentile and 105 percent for caps) are reasonable.

This hedging strategy has also been tested by ACIL Tasman and found to be reasonable. This was achieved by running the contract strategy against the 410 years of price and load data from the price distribution approach. Contract volumes were fixed using the median year load trace of the 410 annual load traces for 2012/13. The hedging strategy was successful in dampening the variation in the 410 annual pool prices and on this basis was judged by ACIL Tasman as a satisfactory approach. This is clearly shown in Figure 13. It shows that the hedging strategy is effective in dampening pool market uncertainty to within a narrow band.

Figure 13 **Annual average load weighted pool prices and annual average prices after hedging for the 410 data years representing the NSLP for 2012/13**



Data source: ACIL Tasman modelling and analysis

3.5 Results from hedging approach

In the settlement process, the hourly prices are brought together with the hourly loads and the contracting prices and quantities for each hour of the year in the hedge model to provide an estimate of the cost of purchasing energy using the hedging approach.

As discussed in the previous section, this settlement process was run for each of the 410 years of pool price and load data from the price distribution approach, and then repeated for each of the individual retail tariff load profiles, as well as for the NSLP profile. In each of these tariff studies the 410 years of hourly pool prices for Queensland and quarterly flat, peak and cap contract prices for Queensland from Table 14 remain unchanged. What changes is the load profile and the contract volumes, which are based on the particular load profile characteristics. However, the contract volumes are determined on the basis of the median year of the 410 data years load traces for the particular tariff and remain unchanged when the hedging model is run against the remaining 409 data years, representing possible variations for 2012/13 for that tariff.

Figure 14 demonstrates that there is not a lot of variation in the price across the 410 years, which suggests that the hedge strategy is consistent with a conservative retailer approach.

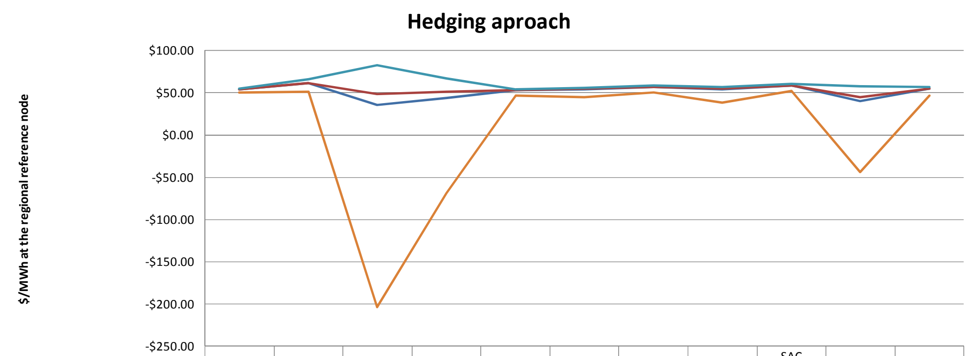
The prices for the two control load tariffs and unmetered supply tariff, which are all mainly operating in the off peak periods, do not suit the hedging strategy. This is because the loads mainly occur in off peak periods and are not suited to base and peak contracts. ACIL Tasman considered applying off-peak contracts to these loads but realised that it would be impossible to match the load profile. To hedge these loads using the peak, off-peak or base contracts is likely to result in a higher price than the average load weighted pool price because of the over contracting involved. However, retailers have the option to hedge these loads along with their other loads and this is the process we have attempted to replicate.

For the control load tariffs ACIL Tasman modelled the price using hedging to calculate the average price of supplying the NSLP with and without the control loads and the difference in price was taken as the price for the controlled loads. For unmetered supply the total Energex load was modelled with and without the unmetered loads and the difference taken as the price for the unmetered loads.

However, this approach resulted in a number of price outliers even though the median and the mean of the 410 annual average prices for these tariffs did not appear to be unreasonable estimates. The outliers appear to arise as a result of random outages in one or more of the 10 outage scenarios causing price spikes in the off-peak period which have a greater impact on the annual price in the cases with the control and unmetered tariffs than without them. Taking the difference between the annual price for the with and without cases consequently results in a negative price for that year.

In fact the mean annual load weighted pool price from the price distribution methodology would probably suffice for these tariffs as un predictable pool price spikes during these off peak periods are extremely rare. On this basis ACIL Tasman would suggest using the mean from the price distribution methodology for the two control tariffs and the unmetered supply tariff rather than the prices out of the hedging process.

Figure 14 **Variation in price across the 410 years - hedging approach**



	Queensland total	NSLP tariffs	Control tariff 9000	Control tariff 9100	ICC tariff 1000	CAC tariff 3500	CAC tariff 4000 & 4500	SAC HV Demand 8000	SAC Demand tariffs 8100 & 8200	Un-metered load 9500	Ergon NSLP
Average - Hedging approach	$54.10	$61.30	$35.62	$44.20	$52.86	$54.18	$56.70	$53.98	$58.62	$39.96	$54.82
Median - Hedging approach	$54.29	$61.60	$48.63	$51.09	$53.12	$54.72	$56.98	$54.79	$58.91	$45.00	$55.16
Max - Hedging approach	$55.06	$66.02	$83.18	$67.21	$53.97	$56.28	$58.30	$57.27	$60.68	$57.44	$56.74
Min - Hedging approach	$50.11	$51.68	-$203.78	-$68.61	$46.81	$44.77	$49.98	$38.85	$52.00	-$43.75	$46.50

Source: ACIL Tasman hedging analysis

ACIL Tasman favours the median price from the 410 annual prices as representing the best estimate of the energy purchase costs apart from the control and un-metered tariffs where the mean of the price distribution approach would seem a more reasonable estimate. Unlike the average of the 410 prices, the median is the point where there is an equal chance of the hedged load being lower as there is of being higher than the actual outcome. Also the median is not affected by any highs or lows which may be regarded as outliers but the average is affected by these potential outliers.

Table 15 shows the modelling results for the hedging approach using the median price. It also includes an allowance for the transmission and distribution losses.

Table 15 **Energy purchase costs using the median price from hedging approach ($/MWh)**

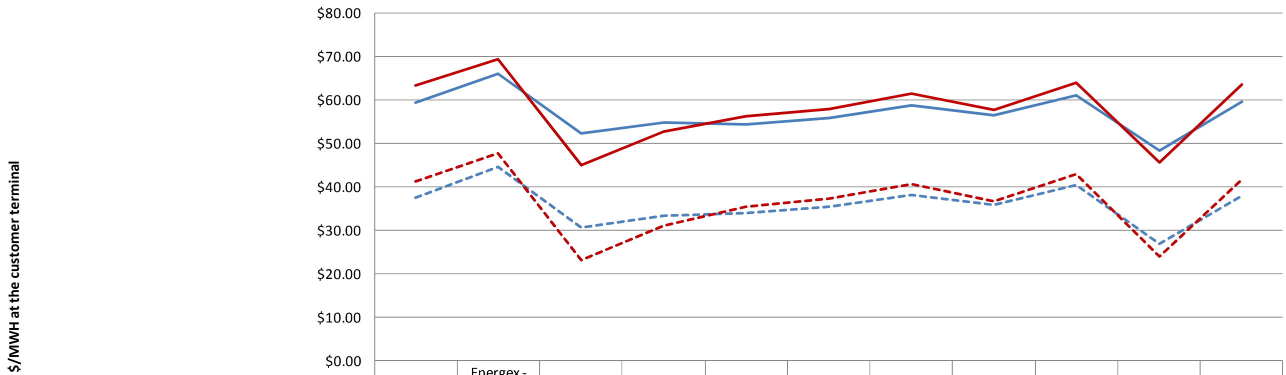
Settlement classes	Median cost at the Queensland reference node using hedging	Allowance for transmission and distribution losses	Estimated wholesale energy purchase costs using hedging strategy at the customer terminal
Prices including carbon pricing			
Energex - NSLP - residential and small business	$61.60	7.4%	$66.13
Energex - Control tariff 9000	$48.63	7.5%	$52.26
Energex - Control tariff 9100	$51.09	7.5%	$54.90
Energex - ICC customers	$53.12	2.6%	$54.51
Energex - CAC customers large	$54.72	2.2%	$55.91
Energex - CAC customers balance	$56.98	3.1%	$58.73
Energex - SAC HV demand customers	$54.79	3.4%	$56.63
Energex - SAC customers balance	$58.91	3.8%	$61.15
Un-metered supply	$45.00	7.5%	$48.35
Ergon Energy - NSLP - ICC, CAC &SAC	$55.16	8.0%	$59.57
Prices without carbon pricing based on 87% pass through			
Energex - NSLP - residential and small business	$41.60	7.4%	$44.65
Energex - Control tariff 9000	$28.63	7.5%	$30.77
Energex - Control tariff 9100	$31.09	7.5%	$33.41
Energex - ICC customers	$33.12	2.6%	$33.98
Energex - CAC customers large	$34.72	2.2%	$35.48
Energex - CAC customers balance	$36.98	3.1%	$38.11
Energex - SAC HV demand customers	$34.79	3.4%	$35.95
Energex - SAC customers balance	$38.91	3.8%	$40.39
Un-metered supply	$25.00	7.5%	$26.86
Ergon Energy - NSLP - ICC, CAC &SAC	$35.15	8.0%	$37.97

Note: *Prices without carbon do not include the assumed 87% pass through of the average carbon price of $23.00/tCO2-e for 2012/13 included in the prices with carbon. The 87 percent pass through means that 87 percent of the carbon price in $/tCO2-e is passes through to the electricity price in $/MWh. This is based on a NEM emissions factor of 0.87tCO2-e/MWh.*

Data source: ACIL Tasman analysis

The results by tariff based on Energex load profiles with and without carbon pricing for the hedging approach and price distribution methodology are summarised in Figure 15. It shows that, apart control tariffs and unmetered supply the price distribution method results in slightly higher prices than the hedging approach.

Figure 15 **Energy purchase costs at the customer terminals – hedging approach vs. price distribution approach with and without carbon**



	Queensland total	Energex - NSLP - residential and small business	Energex - Control tariff 9000	Energex - Control tariff 9100	Energex - ICC customers	Energex - CAC customers large	Energex - CAC customers balance	Energex - SAC HV demand customers	Energex - SAC customers balance	Energex - Un-metered supply	Ergon Energy - NSLP - ICC, CAC &SAC
Hedging approach- with carbon pricing	$59.40	$66.13	$52.26	$54.90	$54.51	$55.91	$58.73	$56.63	$61.15	$48.35	$59.57
Price distribution approach - with carbon pricing	$63.45	$69.46	$44.99	$52.82	$56.32	$57.98	$61.57	$57.69	$64.07	$45.76	$63.55
Hedging approach - without carbon pricing	$37.52	$44.65	$30.77	$33.41	$33.98	$35.48	$38.11	$35.95	$40.39	$26.86	$37.97
Price distribution approach - without carbon pricing	$41.31	$47.75	$23.25	$31.08	$35.57	$37.31	$40.72	$36.77	$43.08	$24.02	$41.70

Data source: ACIL Tasman analysis

The results of the hedging approach shown in Figure 15 suggest that the contract prices used in the analysis, sometimes based on a couple of months of data particularly for the first two quarters of 2013 may be on the low side. Alternatively it could be that the futures market is factoring in the relatively mild summers that have occurred in recent years which is not picked up by the price distribution approach.

As established earlier in this report, in the absence of any consideration of risk, the mean price calculated under the price distribution methodology is the maximum price that a retailer would pay to maximise its position on an expected outcome basis. However, ACIL Tasman assesses that retailers generally face a higher price risk profile than generators and contends that the equilibrium contract price would normally be expected to be above the average price calculated under the price distribution approach.

The result where the prices from the contract hedging approach are lower than the prices from price distribution modelling suggests that generators have a higher risk profile than retailers and the equilibrium contract price is in fact lower than the mean of the price distribution. It could be argued that the lower contract hedge price is due to excess supply of generation in the market combined with uncertainties over carbon price outcomes, which has increased the risk to the generators more than retailers.

4 Renewable energy costs and market fees

The costs estimates shown in this section are as follows.

- Renewable energy costs associated with the Renewable Energy Target (RET) encompassing:
  - Large-scale Renewable Energy Target (LRET)
  - Small-scale Renewable Energy Scheme (SRES)
- Queensland Gas Scheme
- Market fees including:
  - NEM management fees
  - Ancillary services costs

4.1 Renewable Energy Target scheme

On 1 January 2011, the Renewable Energy Target (RET) has two elements: the Large-scale Renewable Energy Target (LRET), and the Small-scale Renewable Energy Scheme (SRES). Liable parties (i.e. all electricity users apart from those wholly or partially exempted for one reason or another such as EITE industries such as aluminium) are now required to comply and surrender certificates for both SRES and LRET.

To determine the costs to retailers of complying with both the LRET and SRES, ACIL Tasman has used in its calculation:

- Large-scale Generation Certificate (LGC) market prices from AFMA[8]
- Adjusted LRET targets for 2012 and 2013 of 16,763GWh and 19,088GWh respectively, as published by Office of the Renewable Energy Regulator (ORER)
- ORER binding estimate for 2012 RPP of 9.15 percent[9]
- ORER binding estimate for 2012 STP of 23.96 percent[10]
- ORER non-binding estimate for 2013 STP of 7.87 percent
- Total liable energy implied from non-binding Small-scale Technology Percentage (STP) estimate, as published by ORER

[8] AFMA data includes weekly settlement prices to 18 January 2012, which is the cut-off date for all relevant market-based data used in the Draft Decision for 2012/13 tariffs.

[9] Published on 24 February 2012

[10] Published on 24 February 2012

- ORER clearing house price for 2012 and 2013 for Small-scale Technology Certificates (STCs) of $40/MWh.

4.1.1 LRET

The estimated 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 little uncertainty over the Renewable Power Percentage (RPP) component of the calculation as this is estimated using data published by ORER. The methodology for determining the price for LGCs is not as straight forward.

ACIL Tasman understands 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 (LRMC) 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 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.

ACIL Tasman has used weekly market prices for LGCs published by AFMA to calculate the price of average LGCs. The average LGC prices calculated from the AFMA data are **$40.62/MWh for 2012** and **$42.89/MWh for 2013.**

The AFMA weekly LGC prices have been averaged over the following periods:

- 2012 is based on prices from 7 January 2010 to 18 January 2012 (106 weeks)

- 2013 is based on prices from 6 January 2011 to 18 January 2012 (54 weeks)

ACIL Tasman has used the ORER binding estimate for 2012 RPP of 9.15 percent.

To arrive at the estimate of 9.97 percent for the 2013 RPP, ACIL Tasman has used the adjusted LRET target published by ORER for 2013 of 19,088 GWh, and divided by the estimate of total liable energy calculated by ACIL Tasman using the ORER's non-binding STP estimate for 2013.

Total liable energy is implied from the non-binding STP estimate for 2013, as published by ORER. ORER published an estimate of 15.07 million STCs for an STP of 7.87 percent which implies a total liable energy for 2013 of 191,487 GWh (i.e. 15,070/0.0787=191,487).

Table 16 shows the published binding ORER estimate of the 2012 RPP and ACIL Tasman's estimate of the 2013 RPP for the LRET scheme.

Table 16 **Elements of the 2012 and 2013 RPP estimates for the LRET scheme [a]**

Calendar Year	Required GWh of renewable source electricity	Total liable energy GWh	Renewable Power Percentage (RPP)
2012	**16,763**	183,202	**9.15%**
2013	**19,088**	191,487	9.97%

[a] **Bold** numbers are published by ORER and non-bold numbers are estimates implied from information published by ORER.

Data source: ORER, ACIL Tasman analysis

Based on this approach, we estimate the cost of complying with the LRET scheme to be $4.00/MWh in 2012/13 as shown in Table 17.

Table 17 **Estimated cost of LRET – 2012/13**

	2012	2013	Cost of LRET Draft Decision 2012/13
RPP %	9.15%	9.97%	
Adjusted target GWh	16,763	19,088	
Average LGC price $/MWh	$40.62	$42.89	
Cost of LRET	**$3.72**	**$4.28**	**$4.00**

Data source: ORER, AFMA, ACIL Tasman analysis

4.1.2 SRES

The cost of SRES is found by applying the STP to the STC price to estimate the cost per MWh for 2012 and 2013. The estimate used for the Draft Decision for 2012/13 tariffs is then taken as the average of the 2012 and 2013 results.

In February 2012 ORER has published the binding estimate for the 2012 STP, which is 23.96 percent. In December 2011 ORER published a non-binding estimate for 2013 of 7.87 percent. ACIL Tasman has used these STPs for purpose of calculating the cost of the SRES component of 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 (as at February 2012) for STCs is around $31.

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 difficulty because of the need to forecast the proportion of STC likely to be traded in the tariff year. Furthermore, while AFMA quotes a market price for STCs the volume traded at this price is unknown.

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 of $40/MWh as the price for STCs.

Based on this approach, we estimate the cost of complying with the SRES to be $6.37/MWh in 2012/13.

Table 18 **Estimated cost of SRES – 2012/13**

	2012	2013	Cost of SRES Draft Decision 2012/13
STP %	23.96%	7.87%	
STC clearing house price $/MWh	$40.00	$40.00	
Cost of SRES	**$9.58**	**$3.15**	**$6.37**

Data source: ORER, ACIL Tasman analysis

Combining the LRET and SRES costs for each year and taking the average of costs in 2012 and 2013 results in a total cost of both schemes of $10.36/MWh.

Table 19 shows the estimated combined cost of LRET and SRES for the 2012/13 tariffs.

Table 19 **Estimated combined cost of LRET and SRES ($/MWh)**

	2012	2013	Cost of RET Draft Decision 2012/13
RPP %	9.15%	9.97%	
Average LGC price $/MWh	$40.62	$42.89	
Cost of LRET	**$3.72**	**$4.28**	**$4.00**
STP %	23.96%	7.87%	
STC clearing house price $/MWh	$40.00	$40.00	
Cost of SRES	**$9.58**	**$3.15**	**$6.37**
Cost of RET	**$13.30**	**$7.42**	**$10.36**

Data sources: ACIL Tasman analysis based on data from ORER and AFMA.

4.2 Queensland Gas Scheme

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.

Retailers have generally stated that this methodology of relying entirely on the AFMA market prices underestimates the cost of the GEC scheme to retailers who 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 available 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 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, the AFMA weekly GEC prices have been averaged over an extended period of 209 weeks or 4 years as follows:

- for 2012 - from 1 Dec 2007 to 31 Dec 2011
- for 2013 - from 1 March 2008 to 18 January 2012

The cut-off date for the AFMA data used for the Draft Decision for 2012/13 tariffs is 18 January 2012. This date will be extended to 31 March 2012 for the Final Decision.

The average GEC prices calculated from the AFMA data are $6.11/MWh for 2012 and $5.42/MWh for 2013. By taking the average of GEC prices in 2012 and 2013, results in a GEC price of $5.77/MWh for 2012/13.

Table 20 **Estimated cost of Queensland Gas Scheme using AFMA data, $/MWh**

	Draft Decision 2012/13
Price of GECs from AFMA data	$5.77
Prescribed percentage	15%
Total cost of Queensland Gas Scheme	**$0.86**

Data sources: ACIL Tasman analysis based on data from AFMA for prices and Queensland Department of Employment, Economic Development and Innovation (DEEDI) for the prescribed percentage.

4.3 NEM fees

NEM participant and FRC fees are payable by retailers to AEMO to cover operational expenditure.

Using AEMO's estimate of NEM fees for 2012/13 in *Final Budget and Fees for 2011-12,* estimated total NEM fees in the Draft Decision for 2012/13 tariffs will be $0.40/MWh.

Table 21 **Estimated NEM fees ($/MWh)**

Cost category	Draft Decision 2012/13
Market participant fees	$0.34
FRC fees	$0.06
Total NEM fees	**$0.40**

Data source: AEMO final budget and fees for 2011-12

4.4 Ancillary services

Weekly aggregated settlements data for ancillary service payments in each interconnected region are provided by AEMO. Based on the average cost over the preceding 52 weeks of currently available ancillary services costs data for the NEM (up to the cut-off date of 18th January 2012 for this report for the

Draft Decision)[11], it is estimated that the cost of ancillary services will be $0.47/MWh for 2012/13.

Table 22 **Estimated ancillary services charges ($/MWh)**

	Draft Decision 2012/13
Ancillary services	$0.47

Data source: ACIL Tasman analysis based on AEMO Ancillary Services payment data

4.5 Summary of renewable energy costs and market fees

In summary, other energy costs for the Draft Decision for 2012/13 tariffs are estimated to be $12.10/MWh.

Table 23 **Summary of renewable energy costs and market fees ($/MWh)**

Cost category	Draft Decision 2012/13
Renewable Energy Target	$10.36
Queensland Gas Scheme	$0.86
NEM fees	$0.40
Ancillary services	$0.47
Total other energy costs	**$12.10**

[11] The cut-off date for the final decision will be 31st March 2012

5 Summary of energy purchase costs

Estimated energy purchase costs for the tariffs and groups of tariffs in the Energex area and for the Ergon Energy NSLP for 2012/13 are presented in Table 24**Error! Reference source not found.**. The costs in the table include both the wholesale EPC and th renewable energy costs and market fees. The results with and without carbon are shown.

Table 24 **Estimated wholesale energy purchase costs for Energex and Ergon Energy settlement classes**

Settlement classes	Wholesale energy purchase cost at the customer terminal ($/MWh)		Renewable energy and market fees ($/MWh)	Total energy purchase costs at the customer terminal ($/MWh)	
	Price distribution approach	Hedging approach		Price distribution approach	Hedging approach
Prices including carbon pricing					
Energex - NSLP - residential and small business	$69.46	$66.13	$12.10	$81.56	$78.23
Energex - Control tariff 9000	$44.99	$52.26	$12.10	$57.09	$64.36
Energex - Control tariff 9100	$52.82	$54.90	$12.10	$64.92	$67.00
Energex - ICC customers	$56.32	$54.51	$12.10	$68.42	$66.61
Energex - CAC customers large	$57.98	$55.91	$12.10	$70.08	$68.01
Energex - CAC customers balance	$61.57	$58.73	$12.10	$73.67	$70.83
Energex - SAC HV demand customers	$57.69	$56.63	$12.10	$69.79	$68.73
Energex - SAC customers balance	$64.07	$61.15	$12.10	$76.17	$73.25
Energex - Un-metered supply	$45.76	$48.35	$12.10	$57.86	$60.45
Ergon Energy - NSLP - ICC, CAC &SAC	$63.55	$59.57	$12.10	$75.65	$71.67
Preliminary prices without carbon pricing based on 87% pass through					
Energex - NSLP - residential and small business	$47.75	$44.65	$12.10	$59.85	$56.75
Energex - Control tariff 9000	$23.25	$30.77	$12.10	$35.35	$42.87
Energex - Control tariff 9100	$31.08	$33.41	$12.10	$43.18	$45.51
Energex - ICC customers	$35.57	$33.98	$12.10	$47.67	$46.08
Energex - CAC customers large	$37.31	$35.48	$12.10	$49.41	$47.58
Energex - CAC customers balance	$40.72	$38.11	$12.10	$52.82	$50.21
Energex - SAC HV demand customers	$36.77	$35.95	$12.10	$48.87	$48.05
Energex - SAC customers balance	$43.08	$40.39	$12.10	$55.18	$52.49
Energex - Un-metered supply	$24.02	$26.86	$12.10	$36.12	$38.96
Ergon Energy - NSLP - ICC, CAC &SAC	$41.70	$37.97	$12.10	$53.80	$50.07

Note: *Prices without carbon do not include the assumed 87% pass through of the average carbon price of $23.00/tCO2-e for 2012/13 included in the prices with carbon. The 87 percent pass through means that 87 percent of the carbon price in $/tCO2-e is passes through to the electricity price in $/MWh. This is based on a NEM emissions factor of 0.87tCO2-e/MWh.*

Data source: ACIL Tasman modelling and analysis

5.1 Choice of energy purchase cost estimate

On the basis that ACIL Tasman has been unable to estimate the risk premium to add to the mean of the price distribution and given the consistency and stability of contract prices since November 2011 when the carbon tax was enacted we believe that the contract hedging is the favoured approach.

5.2 Application of energy purchase cost to the individual retail tariffs

Energy purchase costs for the individual retail tariffs or groups of retail tariffs (ie cost to supply NSLP) should be applied to all energy usage. Any differences in peak and off peak prices for the new residential time of use tariff and business time of use should be built into the network tariff not the cost of energy so as to remove any risks to retailers.