Calculation of energy costs for the 2011-12 BRCI Final Decision

Includes the calculation of long run marginal cost, energy purchase costs, and other energy costs

Prepared for the Queensland Competition Authority

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ACIL Tasman

Economics Policy Strategy

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Contents

List of figures

List of tables

1 Introduction

ACIL Tasman has been engaged by the Queensland Competition Authority (QCA) to assist in the calculation of the energy cost components of the Benchmark Retail Cost Index (BRCI) for the year 2011-12. The parts of the BRCI that ACIL Tasman is providing assistance on are:

- The long run marginal cost (LRMC) of electricity in Queensland. This calculation applies a least cost planning model to develop the lowest cost mix of new plant to provide incremental supply in Queensland.
- The energy purchase cost (EPC), involving a projection of regional reference prices (RRPs) in Queensland using a market simulation model and combining these RRPs with an assumed retailer contracting strategy and contract price projections for the 2011-12 year.
- Other energy costs that apply to electricity generators and retailers in Queensland, comprising;
  - Retailer costs associated with complying with the Commonwealth government's Large-scale Renewable Energy Target (LRET) and Small-scale Renewable Energy Scheme (SRES),
  - Retailer costs associated with complying with the Queensland Government's Gas Scheme,
  - National Electricity Market (NEM) retailer fees, paid by all market participants,
  - Ancillary Service Fees, paid by all retailers to cover ancillary services provided on the network.

The methodology, assumptions, data and forecasts used in each of these calculations along with the results are set out the respective chapters contained in this report.

In determining the methodology to be used in the above calculations ACIL Tasman has been conscious of the provisions of the Electricity Act 1994 and the Electricity Regulation 2006. The latter states in Section 107:

> S107 Consistency of framework with previous tariff years
>
> (1) The theoretical framework must be the same, or substantially the same, from tariff year to tariff year unless—
>
> (a) the pricing entity considers that there is a clear reason to change it; and
>
> (b) the pricing entity has, under section 99, published draft decision material about the reason for the change.

We have interpreted this with the help of the judgment in the case *AGL Energy v QCA & Anor; Origin Energy Retail Ltd v QCA & Anor* [2009] QSC 90 to mean that the methodology for calculating the LRMC should be consistent between successive year calculations unless there is a good reason for change. If the QCA considers a change in methodology is justified a certain process needs to be followed in applying it so as not to distort the year on year change in the BRCI.

Chapter 2 of this report describes the calculation of the LRMC, Chapter 3 the calculation of the EPC and Chapter 4 covers the other components of the cost of energy.

1.1 Summary of results

Table 1provides a summary of the cost of energy components in the 2011-12 BRCI Final Decision, 2011-12 Draft Decision, and 2010-11 BRCI Final Decision. It shows that, while each component has changed to some degree, the overall cost of energy has remained virtually unchanged between the Draft and Final Decisions for the 2011-12 BRCI. It also shows that the overall cost of energy has increased by 1.7% between 2010-11 BRCI Final Decision and 2011-12 BRCI Final Decision.

The workings and reasons behind the changes are discussed in detail in the body of this report.

Table 1 **Summary of results for the energy cost components – 2011-12 BRCI Final Decision, 2011-12 BRCI Draft Decision and 2010-11 BRCI Final Decision**

				% Change	% Change
	Final Decision 2010-11 (with GEC estimate revised)	Draft Decision 2011-12	Final Decision 2011-12	From Final 2010-11	From Draft 2011-12
NEM load (MWh)	37,832,394	37,811,724	37,026,856		
Energy costs ($/MWh)					
LRMC	$58.59	$61.51	$64.44	10.0%	4.8%
Energy purchase costs (EPC)	$58.51	$49.23	$46.50	-20.5%	-5.5%
Energy - based on 50% weighting	$58.55	$55.37	$55.47	-5.3%	0.2%
Renewable Energy Target	$3.05	$7.53	$7.72	153.1%	2.5%
Queensland Gas Scheme **a**	$1.29	$0.56	$0.65	-49.6%	16.1%
NEM fees	$0.34	$0.42	$0.39	14.7%	-7.1%
Ancillary services	$0.39	$0.43	$0.45	15.4%	4.7%
Total energy costs ($MWh)	**$63.62**	**$64.31**	**$64.68**	**1.7%**	**0.6%**
Total energy costs ($ millions)	$2,407	$2,432	$2,395		

2 The calculation of LRMC

2.1 Introduction

The Electricity Regulation 2006, section 105, states the following with respect to the calculation of long run marginal cost (LRMC).

> The theoretical framework must comply with the following principles—
>
> (a) it is generally recognised and understood in economic theory;
>
> (b) the application of the theoretical framework should result in a cost per unit of electricity, expressed in dollars per megawatt hour, that constitutes the cost of energy;
>
> (c) the long run marginal cost of energy should be calculated to meet the demand profile (called the NEM load shape) formed over each half hour electricity trading period of the State for the previous calendar year;
>
> (d) there must not be double-counting of the cost of the schemes mentioned in section 92(2) of the Act.

The least cost modelling approach is similar in principle and application to that used in previous years and we believe it complies with section 105(a) above. The model produces results consistent with sections 105(b) and (c) and we believe the approach, while taking into account the effects of Renewable Energy Certificates (RECs) and Gas Electricity Certificates (GECs) on energy costs, does not double count the effects of these schemes.

In developing the LRMC component of the 2011-12 BRCI ACIL Tasman has taken the following steps.

- Applied recent and widely accepted forecasts of fuel, capital and operating and maintenance (O&M) costs for the range of new entrant power stations in the National Electricity Market (NEM) [1],
- Taken into account state and Commonwealth programs that add or subtract to energy costs, such as the enhanced Renewable Energy Target (RET) and GEC schemes,
- Used these inputs in a least cost supply model which minimizes the costs of meeting future market demand.

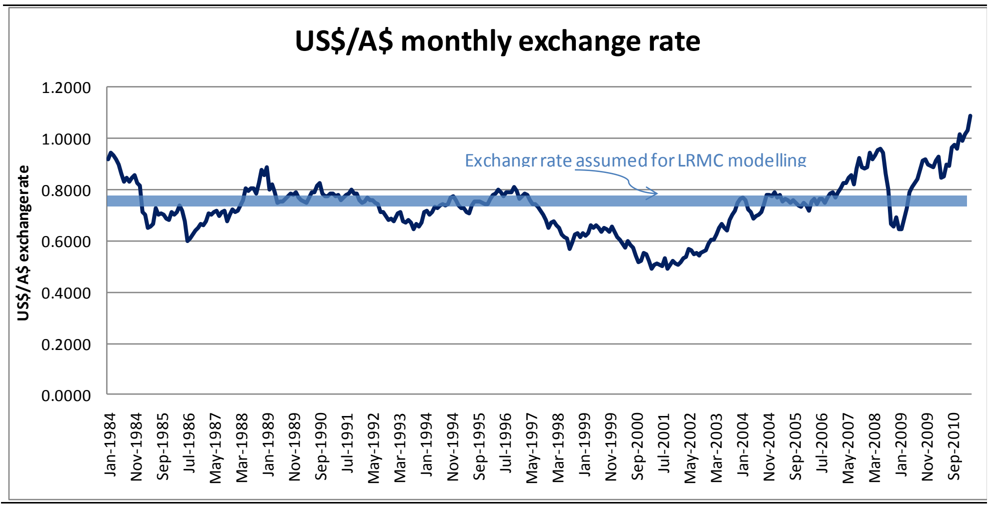
ACIL Tasman used its least cost optmising model, *PowerMark LT*, to calculate the LRMC for each region of the NEM.

[1] These forecasts were inputs to the modelling in the AEMO 2010 National Transmission Network Development Plan (NTNDP), and can be found at http://www.aemo.com.au/planning/2010ntndp_cd/home.htm

The LRMC assumptions for the Final Decision include a forecast of the regional load traces based on the 12 month period to 31 December 2010. Coal and gas prices have been adjusted to reflect recent price levels and industry developments and the components of the weighted average cost of capital (WACC) have been checked to make sure they remain current.

The significant appreciation of the Australian dollar against the US dollar in the past 12 months raises the question about whether imported capital items for power stations should be adjusted. While ACIL Tasman accepts that there will be short term impacts on generation costs, over the longer term considered in the LRMC modelling, generation costs have been based on long term average exchange rate of around US$0.75 /A$ observed since the Australian dollar was floated in 1984. This is illustrated in Figure 1. ACIL Tasman believes that the historic average exchange rate provides a sound long term outlook for exchange rates for use in the LRMC modelling.

Figure 1 **Exchange rate assumed for the LRMC modelling**



Data source: Reserve Bank of Australia

On this basis ACIL Tasman has made no adjustment to generator capital costs in the LRMC modelling to account for the current high US$/A$ exchange rate.

2.2 PowerMark LT

PowerMark LT is a long term planning and analysis tool. It is a dynamic least cost model, which optimises generation investment and operation over the selected period; given assumptions concerning demand growth, generator costs, interconnector capacities, new development costs and government policy settings. *PowerMark LT* utilises a large scale commercial LP solver. The LP matrix itself is reasonably large with approximately 1 million variables, 1.4

million constraints and 2.5 million non-zero coefficients. *PowerMark LT* solves to provide the solution for a single long term scenario (technology, policy settings etc.).

PowerMark LT uses a sampled 50 point sequential representation of demand in each year, with each point weighted such that it provides a realistic representation of the demand population. The sampling utilises a tree clustering process with a weighted pair-group centroid distance measure.

The NEM is modelled on a regional basis with interconnectors represented as bidirectional linkages between regions with defined capacity limits and linear (as opposed to quadratic) loss equations.

In relation to new entry, *PowerMark LT* provides an optimal expansion program which takes into account all generation costs and constructs new generation facilities under the assumption of perfect foresight of future costs. Generation capacity is added as required in a continuous manner (ie the modelling uses a relaxed integer approach). It does not install new plant in normal unit sizes. The approach avoids possible large movements either up or down in the LRMC.

ACIL Tasman agrees with AGL statements in its submission to the Draft Decision that he LRMC under the relaxed integer approach will be lower than a model which installs plant in its normal unit size. However, as acknowledged by AGL, the key issue for the BRCI is that a consistent approach be used year to year so changes in LRMC from one year to the next are comparable whether or not the relaxed integer approach is used.

A range of new entrant technologies are available for deployment in each region, with defined fixed and variable costs. Fixed costs are in the form of an annual charge (specified in $/kW/year), covering capital, fixed O&M and tax. Variable costs (specified in $/MWh), represent fuel and variable O&M. For each technology constraints may be applied to construction limits in any one year or in aggregate.

The long-run is usually defined as a period of time in which all inputs can be varied. In the case of the generation sector the key difference in inputs that can be varied is the capacity of the generation fleet. Therefore, the LRMC is defined as the cost of an incremental unit of generation capacity, spread across each unit of electricity produced over the life of the station.

When calculating LRMC for new generation, the costs considered include all costs relevant to the investment decision. These costs are:

- The capital cost (including connection and other infrastructure)
- Other costs including legal and project management costs

- Fixed O&M costs
- Variable costs over the life of the station
- Tax costs (if using a post-tax discount rate).

ACIL Tasman estimates LRMC for plant based on a Discounted Cash Flow (DCF) new entrant model which is discussed in the following section.

For the calculation of the LRMC of generation used in the 2011-12 BRCI a greenfield development approach has been used. This means the model ignores that there is an existing generation fleet and establishes a new least cost generation fleet.

2.3 Forecasts of capital, fuel and O&M costs

2.3.1 Capital costs

Since the release of the Draft Decision the Australian Energy Market Operator (AEMO) has made public its 2010 National Transmission Network Development Plan (NTNDP) and the associated new entrant generation cost data. In response to the Draft Decision AGL, Origin and TRUenergy all suggested that the Final Decision should be based on this more up to date information.

On the basis that the 2010 NTNDP data is up to date, has been subjected to extensive consultation and is widely accepted by industry experts, ACIL Tasman has decided to use it in modelling the LRMC of generation for the Final Decision on the 2011-12 BRCI.

AEMO has also released data on new entrant generation costs in the lead up to the 2011 NTNDP. However these data are still the subject of consultation and not yet adopted by AEMO for the 2011 NTNDP. ACIL Tasman has, therefore, elected not to use this information.

The underlying cost and other new entrant generation assumptions used for Plan Scenario 3 from the 2010 NTNDP are considered to represent a likely future and as such the assumption used in this LRMC analysis have been closely aligned with those in this "central case". The capital cost estimates include the following cost elements:

- engineering, procurement and construction (EPC)
- planning and approval
- professional services
- land acquisition
- infrastructure costs (incl. water)
- spares and workshop etc

- connection to the electricity network
- fuel connection, handling and storage.

Costs are expressed in A$/kW for each technology and where appropriate have been differentiated based on the method of cooling. The capital cost estimates exclude interest during construction (IDC) as IDC are implicitly included within the new entrant model by incorporating construction profiles.

Table 2 details a selection of key background assumptions that were used for this exercise and as mentioned above, the capital costs shown in Table 2 are sourced from the 2010 NTNDP. We believe they currently represent the most widely accepted and up-to-date view of current capital and O&M costs.

Table 2 **Key assumptions used within the analysis**

Assumption	Value	Comments
Inflation (CPI)	2.50%	Long-term inflation rate at the mid-point of the RBA targeted inflation band. While near-term forecasts exist for CPI (Treasury, RBA etc) a single long-term value is preferable. 2.5% is in-line with Treasury's latest Mid-year Economic and Fiscal Outlook 2010-11 report for years 2012-13 and 2013-14. Treasury is forecasting 3.0% for 2011-12.
Exchange rate (USD/AUD)	0.75	Long-term assumption
International oil price (US$/bbl)	$70 increasing to $110 by 2020	EIA International Energy Outlook 2010 reference case forecast for oil prices over the period to 2020 (2010 dollars)
Internationally traded thermal coal price (A$/tonne)	$92.50	ACIL Tasman projection (in nominal dollars) for FOB Newcastle. Implies FOB price declining in real terms
LNG export facilities developed in Queensland	Total of 16 Mtpa capacity	Assumed two projects (four trains) at Gladstone
Upstream gas developments	ACIL Tasman assumptions	Assumptions relating to level of CSG development and conventional exploration success
Discount rate for new entrants	6.77%	Post-tax real WACC

Table 3 **Capital costs ($/kW, 2011-12 prices)**

	2010-11	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20
Black Coal	$2,811	$2,811	$2,811	$2,811	$2,811	$2,802	$2,783	$2,765	$2,746	$2,727
Brown Coal	$3,752	$3,752	$3,752	$3,752	$3,752	$3,740	$3,715	$3,689	$3,664	$3,639
CCGT	$1,437	$1,437	$1,437	$1,437	$1,437	$1,430	$1,416	$1,403	$1,389	$1,375
OCGT	$1,035	$1,035	$1,035	$1,035	$1,035	$1,031	$1,023	$1,015	$1,007	$999
Wind	$3,032	$3,032	$3,032	$3,032	$3,032	$3,012	$2,971	$2,931	$2,890	$2,850
Hydro	$2,842	$2,842	$2,842	$2,842	$2,842	$2,842	$2,842	$2,842	$2,842	$2,842
Geothermal	$8,415	$8,415	$8,415	$8,415	$8,415	$8,403	$8,381	$8,358	$8,335	$8,313
Biomass	$5,253	$5,253	$5,253	$5,253	$5,253	$5,253	$5,253	$5,253	$5,253	$5,253

Data source: 2010 NTNDP data except, Hydro estimates which are based on ACIL Tasman's estimate

The capital costs for coal fired plant are noticeably higher than those used for the 2011-12 Draft Decision. The capital costs for gas fired plant used for the

Final Decision are similar in the initial years to those used in the Draft Decision but do not decline to the same extent. The much higher capital costs for coal fired power stations extracted from the 2010 NTNDP data base and being used for the Final Decision, have been based on a detailed engineering estimates derived by Electric Power Research institute (EPRI) for AEMO compared with the ACIL Tasman earlier estimates based analysis of cost of coal plant installed over the past decade. However, AEMO accepted ACIL Tasman capital cost estimates for gas fired plant based on the cost of recent plant in Australia and this is the reason why the gas plant capital estimates for the Draft and Final Decisions are similar.

2.3.2 Operation and maintenance costs

O&M costs comprise both fixed and variable components. Variable O&M (VOM) is required for the estimation of short run marginal cost (SRMC), while Fixed O&M (FOM) costs are required for new entrant costs.

Generally, for base load plant in the 2011-12 Final Decision, the FOM costs are lower and VOM costs are higher than those applied in the Draft Decision. The revised FOM and VOM costs for the Final Decision have been taken from the 2010 NTNDP Scenario 3 data base. Table 4 shows that overall O&M (VOM plus FOM) cost from the 2010 NTNDP, used in the Final Decision, tend to be lower for gas plant and higher for coal plant than those from ACIL Tasman's 2009 report used in the Draft Decision.

Table 4 **Overall operation and maintenance costs for key plant($/MWh, 2011-12 prices)**

Plant type	Final Decision 2011/12				Draft Decision 2011-12			
	Capacity factor	FOM	VOM	Total	Capacity factor	FOM	VOM	Total
SC BLACK (AC)	90.1%	$4.39	$4.83	$9.22	90.0%	$6.56	$1.29	$7.85
CCGT (AC)	77.4%	$2.17	$2.10	$4.27	69.7%	$5.47	$1.13	$6.60
OCGT	16.0%	$6.74	$2.63	$9.37	9.5%	$16.91	$8.08	$24.99

Data sources: 2010-11 Draft Decision are from the ACIL Tasman's 2009 report to AEMO on generation cost
2011-12 Final Decision are from the AEMO data base for the 2010 NTNDP report
Capacity factors have been taken from LRMC modelling results

The precise reason for the differences is not clear except that the estimates adopted by AEMO for the 2010 NTNDP are engineering estimates provided by EPRI and not based on actual operating costs of generators in Australia. The earlier estimates developed by ACIL Tasman for its 2009 report to AEMO and used in the Draft Decision were based on a variety of information sources including costs reported by generators in Australia and in-house information on generation costs.

The change in FOM and VOM seems to be largely due to a change in the allocation of maintenance costs to fixed and variable components with more of these costs now estimated to be associated with plant operation rather than being periodic.

Variable O&M (VOM)

The additional O&M costs for an increment of electrical output depends on a number of factors, including the size of the increment in generation, the way in which wear and tear on the generation units is accrued between scheduled maintenance (hours running or a specific number of start-stop cycles) and whether operation is as a base load or peaking facility.

Generally, VOM is a relatively small portion of overall SRMC which is dominated by fuel costs. VOM includes additional consumables such as water, chemicals and energy used in auxiliaries and incremental running costs such as ash handling.

In addition to consumables and additional operating costs, the VOM includes an allowance for some run time maintenance. The reason for including an allowance for maintenance in the VOM is because not all maintenance is periodic, particularly for gas turbines where it is can be determined by hours of operation and specific events such as starts, stops, trips etc.

The VOM values adopted have been extracted from the 2010 NTNDP data. The VOM value is expressed in sent-out terms thereby accounting for internal usage by the station (see below) rather than in 'as generated' terms.

Table 5 **Variable operation and maintenance (VOM) ($/MWh, 2011-12 prices)**

VOM (Real $/MWh sent-out)	Final Decision 2011-12	Draft Decision 2011-12
SC BLACK (AC)	$4.83	$1.29
SC BROWN (AC)	$5.36	$1.29
CCGT (AC)	$2.10	$1.13
OCGT	$2.63	$8.08
Wind	$0.00	$1.89
Hydro	$7.69	$7.69
Geothermal (HDR)	$0.00	$2.15
Biomass	$2.36	$5.05

Note: AC refers to air-cooled power stations

Data sources: 2010-11 Draft Decision are from the ACIL Tasman's 2009 report to AEMO on generation cost
2011-12 Final Decision are from the AEMO data base for the 2010 NTNDP report

Generally the VOM for base load plant (coal and CCGTs) in the Final Decision is higher than used for the Draft Decision because more run-time maintenance is assumed while the VOM for OCGTs is lower because less runtime maintenance is assumed.

The VOM for wind and geothermal have been set to zero for the Final Decision on the assumption that maintenance is all periodic and there are no consumables. The Draft decision included an allowance for maintenance associated with unplanned outages.

Fixed O&M (FOM)

FOM represents costs which are fixed and do not vary with station output, such as major periodic maintenance, wages, insurances and overheads. For stations that are vertically integrated with their fuel supply, FOM costs can also include fixed costs associated with the coal mine/gas field. These costs are presented on a $/MW installed/year basis.

As major maintenance expenditure may not occur every year – major maintenance may only occur every second, third or fourth year – the estimated FOM values represent an annualised average for each station. Similarly to the VOM, the FOM have been extracted from the 2010 NTNDP data.

Table 6 **Fixed operation and maintenance costs (FOM) ($/MW/year, 2011-12 prices)**

FOM (Real $/MW/year)	Final Decision 2011-12	Draft Decision 2011-12
SC BLACK (AC)	$34,671	$51,691
SC BROWN (AC)	$43,076	$59,229
CCGT (AC)	$14,709	$33,384
OCGT	$9,456	$14,000
Wind	$40,974	$22,076
Hydro	$53,581	$54,920
Geothermal (HDR)	$131,328	$37,691
Biomass	$42,025	$53,339

Notes: AC refers to air-cooled power stations,

Data sources: 2010-11 Draft Decision are from the ACIL Tasman's 2009 report to AEMO on generation cost
2011-12 Final Decision are from the AEMO data base for the 2010 NTNDP report

The FOM costs for base load plant are lower for the Final Decision with some more maintenance now assumed to be associated with plant operation rather than periodic. The OCGT has lower FOM: however, this is not because of a transfer from fixed to variable but because the EPRI estimate of overall OCGT operating costs is lower than the earlier ACIL Tasman estimates.

2.3.3 Thermal efficiencies

The thermal efficiency/heat rate for new plants has been estimated in both net and gross terms. These values are presented as a percentage (amount of energy converted from the fuel into electricity sent out) and also in GJ/MWh. The values in Table 7 are based on assumptions presented in the 2010 NTNDP.

Thermal efficiency is presented on Higher Heating Value (HHV) basis which includes the energy required to vaporize water produced as a result of the combustion of the fuel. Efficiencies presented on a HHV basis (as opposed to Lower Heating Value (LHV), are the appropriate measures to calculate fuel use and the marginal costs of generation.[2]

The starting thermal efficiency for new entrants is assumed to remain constant over the life of the station (i.e. no heat rate decay).

Table 7 **Thermal conversion efficiencies (HHV, sent-out values)**

	2011-12
SC BLACK (AC)	38.0%
SC BROWN (AC)	34.9%
CCGT (AC)	49.6%
OCGT	33.2%
Biomass	33.2%

Note: AC refers to air-cooled power stations
Data source: 2010 NTNDP Data

2.3.4 Availability

Availability is the ratio of the potential output of a power station taking in to account downtime for maintenance (both planned and unplanned) and the availability of the primary energy source (such as wind or solar radiation in the case of wind turbines and solar generation) to the output of the power station operating at full capacity with no outages or stoppages over one year.

Availability is a measure of the power station's technical capability to generate over a year. It does not take into account reductions in output or stoppages for market or commercial reasons.

[2] LHV values are often used by turbine manufacturers for comparison as these values are independent of the type of fuel used. Efficiencies in LHV terms are higher when quoted as a percentage (more efficient) than efficiencies in HHV terms.

Table 8 **Availability %**

	2011-12
SC BLACK (AC)	90%
SC BROWN (AC)	90%
CCGT (AC)	92%
OCGT	97%
Wind	30%
Hydro	30%
Geothermal (HDR)	90%
Biomass	85%

Note: AC refers to air-cooled power stations

Data source: ACIL Tasman forecasts

2.3.5 Fuel costs

The supply of fuel into power stations in a greenfields modelling approach is assumed to mirror existing supplies to a certain extent in that lowest cost gas and coal supplies are used first. Coal is assumed to be supplied from a combination of tied and third party sources which, along with long term contractual arrangements, affects the pass through of international coal prices to domestic prices.

There is currently no liquid spot market for either coal or gas in Australia. Therefore, basing fuel costs on an opportunity cost basis (i.e. the current market price as distinct from actual contracted cost) is rarely appropriate.

The commentary on coal and gas prices below provides additional detail on how these forecasts were produced for specific fuels in the different NEM regions and how they were averaged in some cases for use in the greenfields LRMC model.

Coal

Coal prices used in the LRMC modelling are the averaged by state of the coal price forecasts for existing stations. The approach assumes that new coal fired stations would be able to achieve coal prices which are comparable with those currently being experienced in the market at locations which are similar to those currently in existence. The approach could be described as a combination of contractual and other arrangements which has evolved through time that would also apply in a greenfield setting.

However, there are other approaches to pricing coal into a greenfield LRMC model. One might assume, for example, that all greenfield coal plant are mine-mouth with very low marginal costs of under $1.00/GJ similar to the brown coal stations in Victoria or Millmerran and Kogan Creek in Queensland. Using another approach one might assume that all black coal for local generation is faced with export parity pricing of currently around $3.00/GJ. In ACIL Tasman view these approaches represent possible pricing extremes but would not represent realistic average price outcomes for domestic coal prices in a greenfield setting. On this basis ACIL Tasman has chosen to average existing domestic coal prices to provide a realistic estimate of domestic coal prices to use in the LRMC modelling.

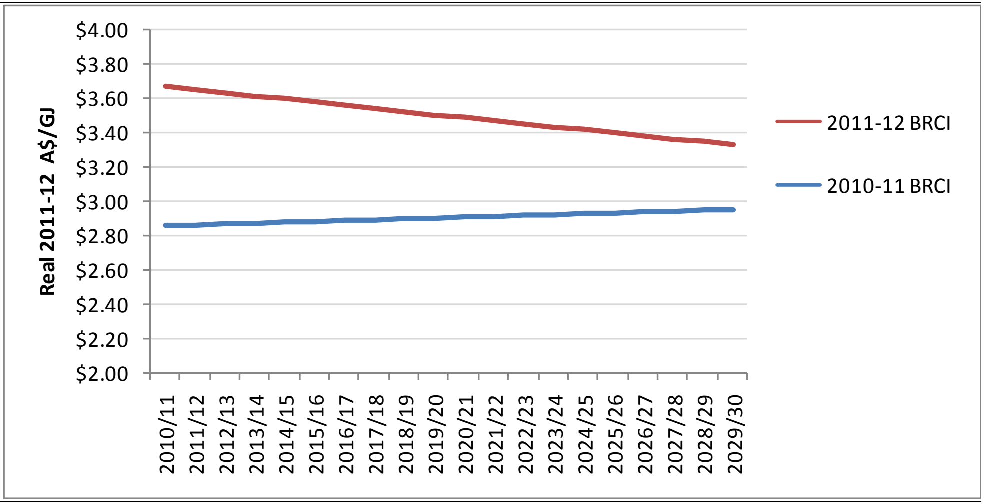
These coal price forecasts take into consideration the expiry of existing contracts and replacement with 80% export parity pricing for replacement tonnage. The comment by Origin that expiring coal contracts have not been fully considered is not correct. However, in coming to this conclusion Origin may not have taken into consideration the fact that in arriving at coal prices for replacement tonnage ACIL Tasman discounts the export parity price by around 20 percent to account for the removal of exchange rate risk, stability provided by longer term contract arrangements, and the acceptability of lower quality coal to domestic power stations.

ACIL Tasman assessment of the Mineral Resource Rent Tax (MRRT) suggests that the new royalty regime will have negligible effect on the price of domestic thermal coal. Mines which exclusively supply local power stations are not high profit operations and unlikely to ever trigger the additional royalty. Furthermore, export prices are not expected to be affected by the new royalty.

Coal prices have been determined in light of the continued strength in the price for thermal coal exports. Coal prices into new entrant black coal fired power stations in NSW will be most affected by the trend in the price of export thermal coal, with new power stations expected to be dependent on new coal supply contracts largely linked to export prices in a similar fashion to those currently existing. The forecast for coal prices into new entrant brown coal stations in Victoria are not influenced by export prices and have not been changed from the 2010-11 BRCI Final Decision. The very high LRMC of greenfield coal fired power stations in South Australia rules out this type of generation in the LRMC modelling.

Export prices affect prices into power stations when they are supplied by third party suppliers with an export option and as coal contracts come up for renewal. The forecast of Free On Board (FOB) export prices for thermal coal used in the 2010-11 BRCI and 2011-12 BRCI are compared in Figure 2.

Figure 2 **Forecasts of FOB price of export thermal coal (real 2011-12 A$/GJ)**



Data source: ACIL Tasman analysis

In arriving at the black coal costs in NSW and Queensland we have averaged the coal prices into the existing stations. This has been done on the assumption that the existing domestic coal supply sources will be available to the new build coal stations in the calculation of LRMC. However Swanbank B, Collinsville and Tarong, which have largely exhausted their existing supply sources, have been excluded from the Queensland average. The average coal price into all existing power stations in NSW is used as the coal price to be faced by new entrant coal fired stations in that state in the LRMC modelling..

The forecast coal prices into the NSW power stations are shown in Table 9. The coal prices into the four NSW generation portfolios take into account the prices in existing contracts and assume that when contracts expire the replacement coal will attract a price of around 80% of the export parity price for that coal. The average of these prices has been used for the NSW coal price in the calculation of LRMC.

Table 9 **Coal prices into NSW power stations (A$/GJ, 2011-12 prices)**

	Macquarie Generation	Eraring Energy	Delta Coastal	Delta Western	Redbank	Coal price used in LRMC modelling
2011/12	$1.44	$1.81	$2.05	$2.05	$1.08	$1.69
2012/13	$1.37	$2.23	$2.12	$2.13	$1.07	$1.79
2013/14	$1.34	$2.23	$2.37	$2.14	$1.07	$1.83
2014/15	$1.40	$2.13	$2.21	$2.17	$1.07	$1.80
2015/16	$1.34	$2.10	$2.13	$2.19	$1.07	$1.77
2016/17	$1.40	$2.07	$2.03	$2.20	$1.06	$1.75
2017/18	$1.57	$2.25	$2.00	$2.31	$1.06	$1.84
2018/19	$1.63	$2.20	$1.98	$2.36	$1.06	$1.85
2019/20	$1.63	$2.24	$1.95	$2.38	$1.06	$1.85

Note: The coal prices show in the ACIL Tasman report used for the Draft Decision were incorrect, being generally displaced by one year

Data source: ACIL Tasman analysis

The forecast coal prices for Queensland existing coal stations used in the LRMC modelling are shown in Table 10. With the exception of Gladstone and Collinsville where coal prices are assumed to be linked to an extent to export prices, coal prices into the Queensland generators are from either captive mines (Millmerran and Kogan Creek) where prices are largely cost based or through long term contracts (Callide B&C and Stanwell) which are more linked to costs rather than export prices. The average of these prices has been used for the Queensland coal price in the calculation of LRMC.

Table 10 **Coal prices into Queensland power stations (A$/GJ, 2011-12 prices)**

	Gladstone	Stanwell	Callide B & C	Millmerran	Kogan Creek	Coal price used in LRMC modelling
2011/12	$1.67	$1.49	$1.41	$0.91	$0.80	$1.26
2012/13	$1.67	$1.49	$1.41	$0.91	$0.80	$1.25
2013/14	$1.66	$1.49	$1.40	$0.90	$0.80	$1.25
2014/15	$1.66	$1.48	$1.40	$0.90	$0.80	$1.25
2015/16	$1.81	$1.48	$1.40	$0.90	$0.79	$1.28
2016/17	$1.81	$1.48	$1.39	$0.90	$0.79	$1.27
2017/18	$1.80	$1.47	$1.39	$0.90	$0.79	$1.27
2018/19	$1.80	$1.47	$1.39	$0.89	$0.79	$1.27
2019/20	$1.79	$1.46	$1.38	$0.89	$0.79	$1.26

Data source: ACIL Tasman analysis

Coal prices used for the 2011-12 BRCI final decision are generally slightly higher than Scenario 3 in the AEMO 2010 NTNDP report and generally reflect a higher export coal price forecast. Coal prices have also been revised to reflect the new coal contracts entered as part of the sale of the NSW generator traders including a commitment to develop Cobbora.

Natural gas

Origin suggested in its submission to the Draft Decision that the gas prices from 2014 are too low and do not fully account for the Queensland liquefied natural gas (LNG) exports and high crude oil prices. The contention is that, with higher levels of LNG production, domestic gas prices will rise to higher levels than assumed in the draft decision. ACIL Tasman agrees with this and as such has opted to use the gas price/volumes from Scenario 3 in the AEMO 2010 NTNDP report which assumes higher LNG production levels.

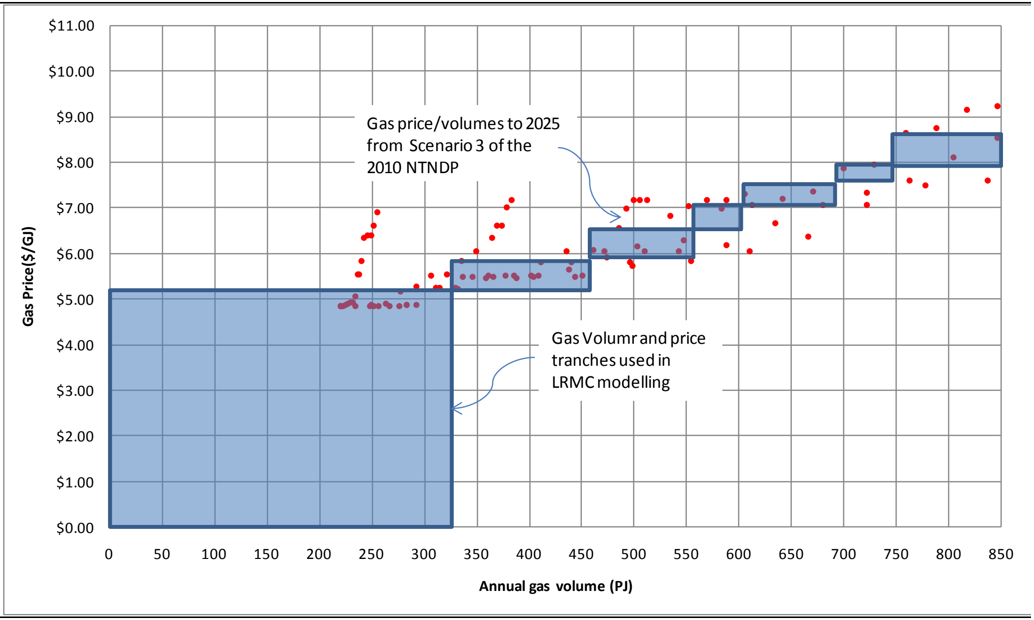
For the Draft Decision ACIL Tasman used the gas prices from its 2009[3] report to AEMO which assumed two LNG trains (8mtpy) in Gladstone based on coal seam gas however these have now been updated to four trains for the 2010 NTNDP report. On this basis ACIL Tasman has elected to use the later gas price/volume forecasts used in the 2010 NTNDP in constructing a gas price/volume estimates for the updated LRMC modelling for the 2011-12 BRCI Final Decision.

The gas price/volume assumptions which have been used in the LRMC modelling for the 2011-12 BRCI Final Decision are shown in Figure 3 and are consistent with similar gas price/volumes used in the 2010 NTNDP central case.

In order to keep the input assumptions for this analysis consistent with the 2010 NTNDP data we have decided to adopt the gas prices provided in the supply input assumptions provided in Scenario 3. The gas prices provided in the 2010 NTNDP data is represented as 7 different gas demand scenarios for a central (Moomba) hub. These scenarios can be used to construct a relationship between the demand and the price of gas. This relationship can be represented in the following way:

[3] Fuel resource, new entry and generation costs in the NEM, 6 April 2009

Figure 3 **NEM gas demand tranches used in LRMC modelling (A$/GJ, 2011-12 prices)**



Data source: ACIL Tasman analysis of 2010 NTNDP data

Figure 3 represents different gas price tranches as demand for gas in the NEM increases. This relationship can be used to generate an active link between the demand for gas and its price within the *PowerMark LT* model. The 2010 NTNDP data also includes transportation differentials between zones and the central hub price such that separate prices can be calculated for new entrant generators in each NEM region.

Gas price in each region in the Draft Decision are similar to the gas prices used for the initial lowest priced tranche of gas. The gas prices for subsequent tranches used in the Final Decision are higher than those used in the Draft Decision. Because in the LRMC modelling gas from these subsequent tranches is required, the gas prices generally in the Final Decision are somewhat higher than those in the Draft Decision.

2.3.6 New entrant model

The new entrant model utilised by ACIL Tasman is a simplified DCF model for a greenfield generation project. It is significantly simpler than a DCF model which would be utilised to evaluate an actual investment decision for a specific project due to the fact that it is by definition generic and designed to be suitable for a range of projects and proponents.

Cash flows within the model are evaluated on an un-geared post-tax basis and include the effect of depreciation. A geared project post tax WACC is used as the project discount rate in effect incorporating gearing upstream. However, the cash flows do not directly include the effects of the interest tax shield and dividend imputation credits.

The model includes an estimate of build time for each of the new entrant technologies and capital expenditure is spread out over this period. The discounted cash flow calculation is started from year zero (before any construction begins) and the first years record negative cash flows incurred through project capital expenditure discounted each year by the WACC. When positive cash flows commence they begin to reduce this accumulation of negative cash flow. Spreading out construction costs in this way means that capital costs have effectively been increased by interest costs over the construction period.

2.3.7 WACC for new entrants

ACIL Tasman uses a calculated WACC as a conservative proxy for an investment decision hurdle rate in the new entrant financial model within the LRMC modelling.

The discount rate used within the new entrant model is a calculated post-tax real WACC. A post-tax WACC is used because of the importance of tax depreciation for capital intensive plant such as power stations.

When using a DCF a number of WACC derivations and cash flow models can be used. Choices need to be made as to whether the analysis is performed on a real or nominal, pre or post-tax basis. Once this has been decided, the model can either incorporate items such as the interest tax shield (recognition of the deductibility of interest payments for tax purposes) and imputation credits explicitly within the cash flows, or alternatively via adjustment to the WACC itself. The cash flows used in the greenfield new entrant cost calculations are designed to be consistent with the Officer WACC definition used. There are a number different expressions for post-tax WACC, the most common ones include:[4]

- Vanilla
- Monkhouse
- Officer.

The Officer formula is the most complex of these owing to the fact that it incorporates all tax effects in the WACC calculation itself and is applied to simple post-tax cash flows. The Officer WACC is the most widely cited as the target post-tax WACC because it is commonly used for asset valuation and project evaluation.

[4] Each of these formulae is equivalent if the analysis is performed on a pre-tax basis.

As the Officer WACC formula includes the interest tax shield and imputation credits there is potential for inaccuracies to exist as it is essentially a simplification. This is particularly so in the case of finite projects that have different amounts of depreciation and tax payable throughout the project life.

A more accurate means of accounting for these elements can be achieved by incorporating them explicitly into the cash flows and using a Vanilla WACC. However, assumptions then need to be made regarding the type, structure and tenure of debt finance for the project which does not lend itself to the generic analysis that is associated with the LRMC financial model.

In the new entrant model used here the post-tax real Officer WACC is applied to un-geared cash flows which, for consistency with the WACC, do not include the effects of the interest tax shield or dividend imputation credits.

The post-tax nominal Officer WACC used in the new entrant cost model for input to the LRMC modelling is expressed as:

$$WACC_{Officer(post-tax\ nominal)} = \frac{E}{V} \times R_e \left(\frac{(1 - T_E)}{\left(1 - T_E(1 - G)\right)} \right) + \frac{D}{V} \times R_d (1 - T_E)$$

Where:

- E is the total market value of equity, 0.4
- D is the total market value of debt, 0.6
- V is the total enterprise value (value of debt plus equity), 1
- R_e is the nominal post-tax cost of equity, 16.2%
- R_d is the nominal post-tax cost of debt, 8%
- T_E is the effective corporate tax rate, 22.5%
- G (Gamma), which is the value of imputation tax credits as a proportion of the tax credits paid, 0.5

This gives a post-tax nominal result of **9.46%.**

The nominal post-tax WACC is adjusted into real terms using the Fischer equation as follows:

$$WACC_{Officer(post-tax\ real)} = \left(\frac{\left(1 + WACC_{Officer(post-tax\ nominal)}\right)}{(1 + F)} \right) - 1$$

Where: F is the relevant inflation rate, assumed at 2.5%.

The Officer WACC is applied to cash flows that do not include the effects of the interest tax shield and dividend imputation credits. That is, cash flows are un-geared and defined simply as:

$$Cash\ Flows_{(Officer)} = X \times (1 - T)$$

Where:

- X is the project cash flow
- T is the statutory corporate tax rate.

The debt to equity ratio of 60/40 has been adopted based on ACIL Tasman's industry experience. This gearing ratio is also in line with the gearing ratio used by the Australian Energy Regulator (AER) in the past (for example see: "Electricity transmission and distribution network service providers: Review of the weighted average cost of capital", AER, March 2009).

The risk free rate has been updated by taking the average daily yield on 10 year commonwealth bonds over the period since5 May 2009. The 5 May 2009 has been selected as it would appear the government 10 year bond rate settled to a new level from that point onward (see Figure 4). This approach has been chosen to represent the long-run nature of the modelling approach applied. The yields were sourced from RBA data[5]. This process yields a risk free rate of 5.4%.

The 10 year bond rate has been chosen based on the long term investment nature of the assets. The 10 year bond rate is assumed to reflect the long term investment horizon of the investment decision as compared with a shorter (5 year bond rate) which is more aligned with a regulatory period[6].

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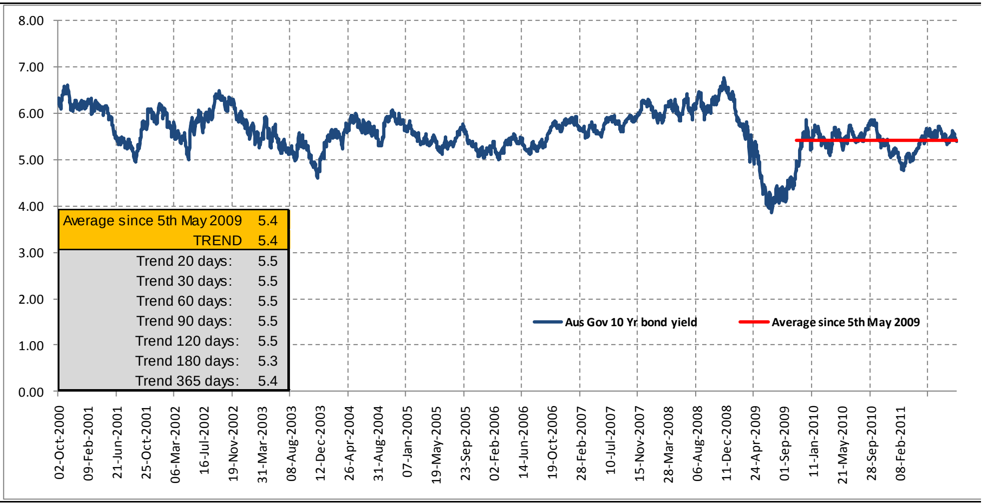
[5] RBA, "Capital Market Yields – Government Bonds - Daily", sourced on 4 May 2011.

[6] ValueAdvisor Associates, *Term of the risk free rate, - A report prepared for Energy Networks Association, Australian Pipeline Industry Association and Grid Australia,* September 2008.

Figure 4 **Australian government 10 year bond rate since 2000**



Data source: RBA, "Indicative Mid Rates of Selected Commonwealth Government Securities", sourced on 3 May 2011

The debt basis point premium is usually estimated with reference to the number of basis points by which a group of representative company BBB+ rated bonds exceed the risk free rate. In a recently completed paper[7] the Independent Pricing and Regulatory Tribunal (IPART) of NSW indicate a debt basis point premium of about 280. In its recent retail price draft decision[8], IPART suggests a wide possible range in the debt margin between 1.4% and 4.1% which includes 12.5 basis points for debt raising costs. This range has been based on selected securities from the Australian bond market with a credit rating of BBB to BBB+ which have at least 2 years to maturity. While IPART has opted for a 3% debt margin which includes 20 basis points for debt raising costs in its final decision, the fact remains that there is a wide dispersion in debt margins between BBB companies. In a recent decision (on gas distribution) the AER[9] selected a debt basis point premium of 335.

AGL have stated that the higher the gearing then the higher the debt basis points premium. AGL have then suggested that the 300 debt basis points premium used in the Draft Decision may not be consistent with a 60/40 debt equity ratio and if the ratio was retained the basis points should be increased.

ACIL Tasman agrees with AGL's observations of the link between gearing level and the debt basis points premium. However, the project funding information on four recent electricity transactions compiled by KPMG and presented by AGL to support its case for a higher debt basis points premium involved brown coal and wind farms. ACIL Tasman would argue that both

[7] "IPART's Weighted Average Cost of capital", IPART, April 2010.

[8] "Changes in regulated electricity retail prices from j July 2011", IPART, March 2011.

[9] AER, "Final Decision, access arrangement proposal; ACT, Queanbeyan and Palerang gas distribution network". Canberra, March 2010

these types of electricity project have higher risks than either black coal or combined or open cycle gas turbines which are the predominant new entrant in the LRMC modelling. This higher risk for brown coal stations is due to the possible impact of future emissions pricing and for wind farms the risk is higher because they are subjected to both electricity price and LGC price uncertainties.

LRMC modelling is over an extended time frame and the debt basis points chosen are intended to represent a long term view of the riskiness of electricity generation projects. The debt financing cited by AGL has been undertaken in a period of heightened uncertainty due to the impending introduction of a price on carbon and are therefore likely to overstate the debt basis points premium for electricity projects in the long term.

Given the degree of uncertainty over the debt basis points premium as implied by the wide range shown in the IPART analysis for its draft decision and because, as shown by AGL, the debt basis points premiums for higher risk electricity generation projects in a period of heightened uncertainty seem to be in the range 325 to 450, ACIL Tasman can see no reason to move from the 300 debt basis point premium and a 60:40 debt to equity ratio for calculating the WACC used in the 2011-12 BRCI Final Decision. In addition the 300 debt basis points premium with the 60:40 debt to equity ratio has been used by ACIL Tasman in undertaking long term modelling for a number of major electricity sector transactions where it has been scrutinised by both banks and equity participants.

The above IPART and AER reports were also referred to when updating the market risk premium. The AER suggest a level of 6.5% for this parameter while IPART suggest a range of 5.5 to 6.5%. We have used 6.0% in this report.

Other parameters used for this Final Decision have been kept at the same levels as used for the 2010-11 BRCI Draft Decision.

Table 11 **WACC parameters**

	Parameter	2011-12
D+E	Liabilities	100%
D	Debt	60%
E	Equity	40%
rf	Risk free RoR	5.4%
MRP = (rm-rf)	Market risk premium	6.0%
rm	Market RoR	11.4%
T	Corporate tax rate	30%
Te	Effective tax rate	22.5%
	Debt basis point premium	300
rd	Cost of debt	8.4%
G	Gamma	0.50
ba	Asset Beta	0.80
bd	Debt Beta	0.16
be	Equity Beta	1.75
re	Required return on equity	15.9%
F	Inflation	2.50%

These parameters result in a post tax real Officer WACC of 6.79% to be used for the 2011-12 BRCI Final Decision. The only minor change to the WACC parameters from the Draft Decision is the slight increase in the risk free rate from 5.38% to 5.4% to reflect the later data on the ten year bond yield. This had the effect of increasing the WACC by 0.02 percentage points.

2.3.8 The Average Loss Factor (ALF)

The electricity generated and sent out by power stations is paid for at the Regional Reference Node (RRN). The LRMC modelling needs to take into account the average transmission loss between the power station and the RRN. In the case of specific power stations operating at a particular location, the appropriate loss factor to use in taking account of transmission losses would be the Marginal Loss Factor (MLF) at the power station's node. The LRMC modelling undertaken here is modelling generic power stations within the Queensland (and other) regions and the appropriate transmission loss factor is the average for the Queensland region, the average loss factor (ALF).

The ALF has been calculated in a similar way to previous years. Powerlink's Annual Planning Review, 2010, on page 26 provides a forecast of 2011-12 Queensland transmission losses (2,009GWh) and sent-out energy (54,297GWh) and dividing the former by the latter gives a forecast ALF of 3.7%.

2.4 Methodology

In calculating the 2011-12 LRMC the PowerMark LT model has been run in so-called "greenfields" mode. This mode assumes that no plant already exists (that is, the existing plant in the NEM have been removed from the PowerMark LT database) and the model builds from zero the most efficient (least cost) combination of plant to meet the demand duration curve. It builds a combination of base load, mid merit and peaking plant and uses the market's modelled price duration curve to govern the entry of different types and costs of new investment. The calculated regional reference prices (RRPs) for a given year are therefore the LRMC in each region of the market as they are the prices that support the least cost combination of new plant.

The model is multi-regional and temporal and therefore includes the effects of regional differences in input assumptions (such as different fuel costs in each state) and changes in the input assumptions during the model horizon. For example, the lower fuel costs in Queensland result in the model finding a solution which includes Queensland generators exporting electricity into NSW.

The long term model draws on the individual life cycle costs of the available generation technologies from the individual new entrant financial models for each technology, each year and each region to select the lowest cost technologies.

PowerMark LT is run for 2011-12 to 2019-20 inclusive (nine years). As we noted in last years' report, we believe that a 9 year horizon provides a more realistic outlook for the LRMC than a one or three year outlook in that it allows new generators to take into account reasonably foreseeable events, such as changes in gas and coal prices. Restricting the period over which the LRMC is calculated effectively cuts down the foresight of the hypothetical new entrants and maintains their costs and prices at present day levels.

Consistent with the assumptions used in the 2010-11 LRMC modelling, the 2011-12 LRMC modelling does not explicitly include any changes that might follow from the introduction of an emissions trading scheme (ETS) in Australia. The date of introduction and the price of emissions permits are both still uncertain and we have opted to exclude these effects on this basis.

2.4.1 Demand

For the Final Decision the demand duration curve for the model has been built from actual NEM regional half-hourly load traces for the 12 month period ending 31 December 2010. This base load trace contains more typical weather conditions of November 2010 as compared to the atypical November 2009 base load trace included in the Draft Decision. The flood related supply disruptions caused by the January 2011 floods are not contained within the current base load trace..

These demands are on as "as generated" basis and include electricity delivered from the transmission system to the distribution system as well as demand of end-users directly connected to the transmission system, consistent with the Supreme Court decision on the Judicial Review of the 2008-09 BRCI.

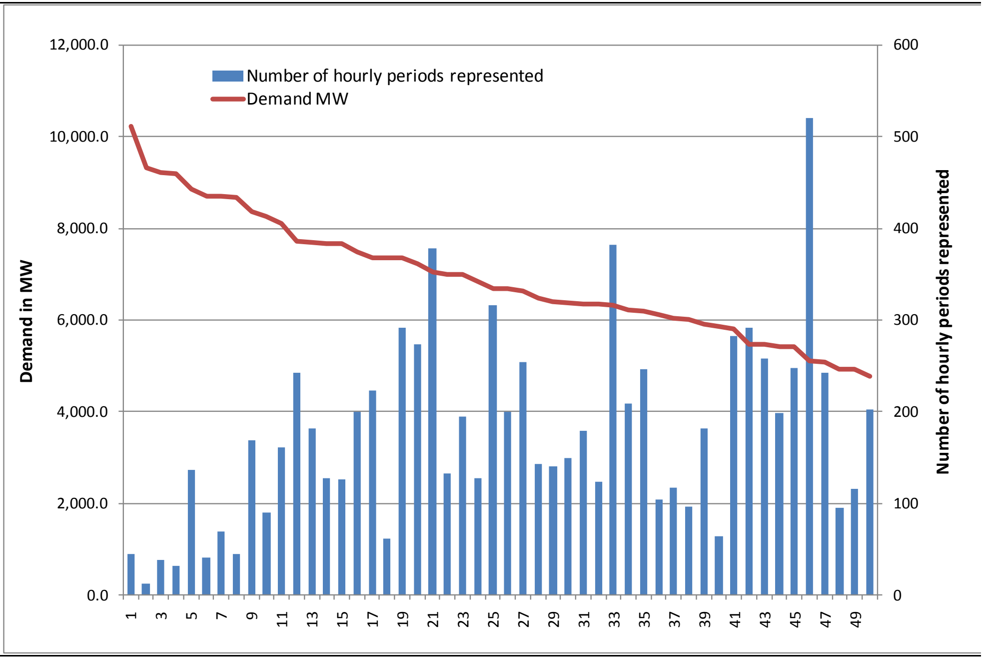
For the LRMC modelling a sample of 50 regional demands was selected from the set of half-hourly demands to represent the entire year. This sample set is selected to best represent the distribution of demands in each region on an annual basis as well as to best represent the relationship between demands across the regions (that is, the coincidence of demands).

Each of the 50 regional demands in the sample set has a weighting and weightings sum to 8,760.

The sample demand set is then grown for each of the years between 2011-12 and 2019-20 inclusive based on the forecasts of annual regional maximum demand and regional energy use published in the 2010 AEMO Electricity Statement of Opportunities (ESOO). The selection of the 50 regional demands is not stratified by season and therefore the sample set does not explicitly distinguish between summer and winter. As a consequence the sample set is grown to a single peak demand in each region and not both the summer and winter peaks. The peak selected is the maximum of the two seasonal peaks published in the ESOO. This is the same as the approach taken for the 2010-11 BRCI calculation and is similar to the approach used in previous years by Charles River Associates (CRA).

PowerMark LT uses "as-generated" demands, not "sent-out" (after internal usage has been deducted). Therefore, the energy parameter in the ESOO (which is reported on a sent-out basis) is increased to "as-generated" by using the scaling factors provided in the Powerlink 2010 Annual Planning Review. The 50 demand points and associated occurrences are presented in Figure 5

Figure 5 **50 demand points and number of hourly periods represented for Queensland in 2011-12**



Source: if ACIL Tasman LRMC Modelling

2.4.2 Transmission

PowerMark LT includes the existing interconnectors and optimises their use. However, intraregional transmission is not modelled and all generation and consumption is assumed to be at the state regional reference nodes. Again, this appears consistent with the approach taken in previous years.

2.4.3 Other factors

GEC Scheme

The modelling assumes the Queensland Gas Electricity Certificate (GEC) Scheme continues to 31 December 2019. The GEC price is subtracted from the SRMC of gas-fired plant in Queensland – this deduction increases the attractiveness of these plant types which results in more CCGT/OCGTs being included in the optimal plant mix for Queensland.

The GEC price used in the LRMC modelling is determined by whether or not the GEC target percentage is achieved. The modelling starts with the penalty as the price and then if there is an oversupply of GECs then the GEC price is lowered and the model re run. It normally takes a number of iterations of the model to achieve a stable solution of gas-fired penetration and GEC price. GEC price is adjusted downwards at each iteration until the gas generation just matches the target percentage or the GEC price is zero. The LRMC modelling for the Final Decision has a zero GEC price because GEC is not needed for gas fired generation be viable and meet the targeted percentage.

This process is designed to reflect the current policy settings under a greenfields approach rather than taking current market prices for GECs which reflect the current generation configuration. This is similar to the approach taken in previous BRCI calculations.

Enhanced RET scheme

The enhanced RET scheme is included with the LGC price fixed at the penalty. The LGC price is subtracted from the LRMC of the renewable plant in all regions. Even with the LGC price set at the penalty the enhanced renewable energy target (RET) is not met in the greenfield LRMC modelling undertaken for the Final Decision where it is assumed there is no price on carbon. This finding is consistent with the results from detailed modelling of the renewable energy sector which shows that the 2020 RET is only met where the LGC price is close to the penalty and the carbon price is at the higher end of modeled prices. This approach is comparable to the approach taken for the previous BRCI.

2.5 Results

The results from the LRMC modelling for the 2011-12 Final Decision are compared to the 2010-11 Draft Decision in Table 12. The main differences can be summarised as:

- higher coal fired capacity and lower gas generation capacity in Queensland
- higher capacity factor for both OCGT and CCGT
- virtually unchanged capacity factor for the coal fired stations.

These changes are mainly due to the changes in capital and O&M costs and partly to increased gas prices. For the Final Decision we have also used a more refined approach to gas volumes/pricing which limits the gas plant capacity under seven gas price/volume tiers.

Table 12 **ACIL Tasman LRMC results for Queensland for 2011-12 Draft and Final Decisions**

	SRMC[1] (2011-12 $/MWh)	LRMC ($/MWh)	Plant capacity (MW)	Dispatch (GWh)	Capacity factor (%)	Market share (%)	Capacity share (%)
2011-12 Draft Decision							
Coal	$12.61	$51.52	4,415	34,808	90.00%	55.68%	43.01%
CCGT	$28.36	$62.28	4,334	26,448	69.67%	42.31%	42.21%
OCGT	$72.76	$228.37	1,518	1,256	9.45%	2.01%	14.78%
Total			10,266	62,512		100.00%	100.00%
2011-12 Final Decision							
Coal	$16.15	$61.66	5,606	44,248	90.10%	65.04%	53.23%
CCGT Tier 1 [2]	$33.87	$56.22	2,092	16,494	90.00%	24.25%	19.87%
CCGT Tier 2[2]	$40.59	$78.77	1,046	4,780	52.16%	7.03%	9.93%
CCGT (average)	$35.38	$61.28	3,138	21,274	77.39%	31.27%	29.80%
OCGT Tier1	$63.22	$135.91	1,248	2,014	18.42%	2.96%	11.85%
OCGT Tier2	$76.03	$204.32	539	493	10.44%	0.72%	5.12%
OCGT (average)	$65.74	$149.36	1,787	2,507	16.02%	3.69%	16.97%
Total			10,531	68,029		100.00%	100.00%
% change							
Coal	28.06%	19.69%	26.98%	27.12%	0.11%	16.82%	23.77%
CCGT (average)	24.76%	-1.60%	-27.59%	-19.56%	11.08%	-26.09%	-29.40%
OCGT (average)	-9.65%	-34.60%	17.71%	99.60%	69.48%	83.34%	14.80%
Total			2.59%	8.83%		0.00%	0.00%

Data source: ACIL Tasman modelling
Notes: 1. SRMC for CCGT in Queensland includes GECs, but these have no affect as GEC the price is assumed to be zero
2. The gas fired CCGT base load capacity has been split into seven tiers to reflect gas volume price limitations (see Figure 3).

The energy dispatched by Queensland power stations includes net interconnector flows. The higher level of dispatch in modelling for the Final Decision (i.e. 68,029GWh compared with 62,512GWh in the Draft decision) can be attributed to an increase in net interconnector flows from Queensland.

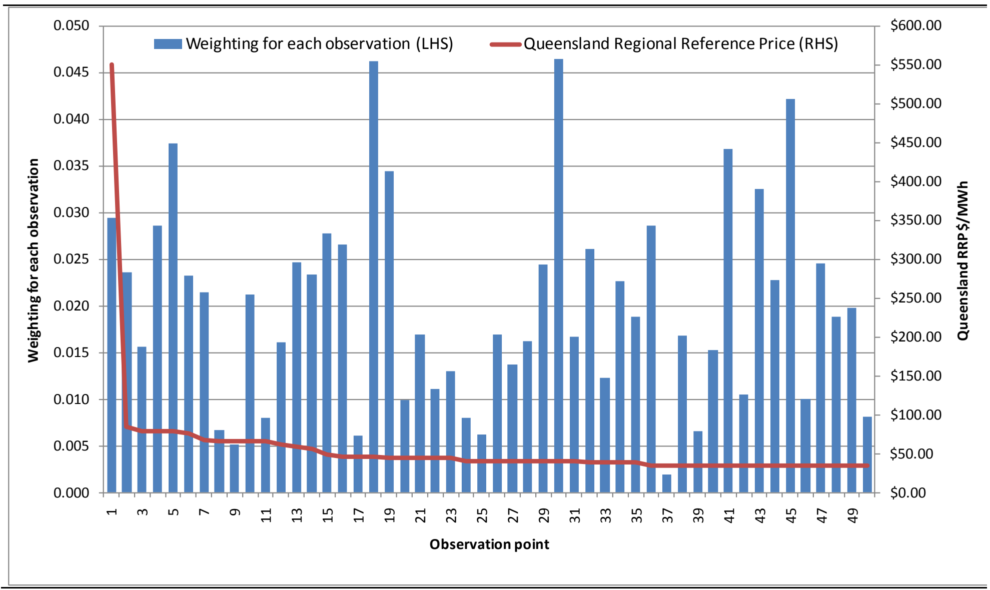
For comparison purposes the CCGT and OCGT figures for Tier 1 and Tier 2 gas prices/volumes have been averaged to allow comparison between Draft and Final Decision results.

The move to a tiered gas price/volume approach in the LRMC modelling for the Final Decision was necessary because the higher capital and other costs for coal fired plant meant that the system became totally reliant on gas fired plant. This resulted in a very high gas requirement which would require a significantly higher gas price than assumed in the Draft Decision. Rather than attempt to select a single gas price which resulted in a reasonable plant balance, ACIL Tasman opted for a tiered approach of constraining the capacity of gas fired base load generation at each gas pricing point.

The two lowest price tiers are active in Queensland in 2011-12. The gas price/volume tiers were not considered necessary in the LRMC Modelling for the Draft Decision as coal fired plant limited the gas consumption in the NEM at significantly lower level.

The LRMC modelling produced Queensland RRPs which varied from a high of $550/MWh when expensive peaking plant had to be employed to a low of $33.87/MWh being the SRMC of a CCGT using gas from the lowest pricing tier. The prices for the 50 pricing points and respective weightings are shown in Figure 6.

Figure 6 **Queensland RRP and weightings for the 50 pricing points for 2011-12 from the LRMC modelling**



Notes: The weigh ings add to one and are a combination of the number of periods and the demand representing each of the 50 pricing points.
Source: ACIL Tasman *Powermark LT* modelling

The resultant load weighted LRMC of electricity in Queensland in 2011-12 for use in the Final Decision is **$64.44/MWh**. The $64.44/MWh is the average of the 50 modelled prices weighted by the number of periods and load representing the 50 pricing points. The estimate also applies an allowance of 3.7% to cover average transmission losses in the Queensland region of the NEM.

This result is higher than $61.51 presented in the report for the 2011-12 Draft Decision. This change is mainly due to the change in the new capital, O&M costs and partly due to the change in the gas price and the move to a gas price/volume approach.

3 Energy purchase costs (EPC)

In order to maintain consistency in the methodology applied to the EPC calculation ACIL Tasman has followed the methodology applied in the calculation of the 2010-11 BRCI, which was in turn based on the methodology applied by CRA for the 2009-10 BRCI.

The methodology is summarised briefly in the following steps.

- Develop a load trace for the NEM load for Queensland (the small load) which is total load at the Queensland TNIs (the large load) minus the load of directly connected customers.
- Prepare a forecast for the "as generated" load traces for the NEM regions based on the recorded half hour data to 31 March 2011 from the load forecast in the AEMO 2010 ESOO.
- Using the load traces for the NEM regions, carry out simulation market modelling for the 2011-12 financial year providing a projection of RRPs for each half hour of the year in each region of the NEM, including Queensland.
- Calculate swap and cap contracts contract volumes for each half hour of 2011-12 by applying the retailer's contracting strategy developed in previous in previous years to manage the risks in supplying the NEM load for Queensland (small load). The strategy includes the use of two-way (swap) and one-way (cap) contracts.
- Estimate swap and contract prices for each half hour period in 2011-12 using prices from the d-cypha Trade database of contract prices.
- Combine the half hourly RRPs, the load trace of the half-hourly small load and the half hourly contract volumes and prices in a spreadsheet model to produce the cost in each half hour for a retailer supplying the small load. The cost outcome reflects the payments made to AEMO for pool purchases at the projected RRP as well as difference payments paid by or to the retailer for swap contracts, premiums paid for cap contracts and any payments from cap contracts.

The remainder of this chapter provides more detail on each of these steps.

3.1 The load forecasts

ACIL Tasman has forecast the load traces for the total (large) load for Queensland and for the "as generated" load in each of the NEM regions using its load shape forecast program. The method involved transforming:

- the actual half hourly load traces for total (large) load for Queensland for the year to 31 March 2011 to match the Powerlink 2010 APR forecasts of winter and summer maximum demand and annual energy.

- the "as generated" load traces for each NEM region for the year to 31 March 2011 to match the AEMO 2010 ESOO forecasts for summer and winter peaks and annual energy for 2011-12.

The forecast load trace for the total (large) load for Queensland is measured at the point of delivery from the transmission network.

The NEM load (or small load) for Queensland is defined as the total load delivered from the transmission network to customers on distribution networks minus the load of customers that are directly connected to the transmission network. These loads do not include transmission losses or energy used in power station auxiliaries.

The "as generated" load in each NEM region is measured at the generator terminals and includes power station auxiliaries and transmission losses.

The forecast load trace for the total (large) load for Queensland is used in calculating the NEM (small) load for Queensland, which in turn is used in the calculation used to determine retail energy purchase costs.

The generated load in the NEM regions is used in modelling the 2011-12 half hour RRPs needed to calculate the cost of energy.

The total (large) Queensland load and the NEM regional load forecast for 2011-12 are lined up on a half hour basis to ensure the loads and prices are consistent with each other in the calculation of the cost of energy.

3.1.1 Half-hourly load trace data for Queensland

ACIL Tasman aggregated the half-hourly load data for each Queensland TNI for the year to 31 March 2011, as supplied by QCA, into the total load for Queensland including directly connected customer load.

3.1.2 Load forecasts for Queensland and NEM Regions

The forecasts of the following items for 2011-12 are then extracted from the Powerlink 2010 APR:

- **Annual scheduled energy delivered** from the transmission system based on the medium economic forecasts (i.e. Native Energy minus the Delivered Energy Adjustment to account for embedded non-scheduled generation)
- **Scheduled summer maximum demand delivered** from the transmission system under the medium economic forecasts at 10%, 50% and 90% probability of exceedence (POE).
- **Scheduled winter maximum demand delivered** from the transmission system under the medium economic forecast at 10%, 50% and 90% POE.

- **Coincident demand of directly connected customers in summer and winter** taken from the table showing Connection Point Native Demands Coincident with State.

The following forecasts for each NEM region were also extracted from the AEMO 2010 ESOO to produce the NEM regional load traces used in the modelling of 2011-12 RRPs:

- **Annual scheduled and semi scheduled energy sent-out from power stations** system based on the medium economic forecasts
- **Scheduled and semi scheduled generated summer maximum demand** under the medium economic forecasts at 10%, 50% and 90% POE.
- **Scheduled and semi scheduled generated winter maximum demand** under the medium economic forecasts at 10%, 50% and 90% POE.

3.1.3 Forecast of minimum demand for Queensland

A forecast of minimum demand is produced by ACIL Tasman by projecting the observed minimum half-hourly load from the actual load traces at the forecast growth in annual energy. The minimum load for both the total load for Queensland and the generated load for each NEM region was forecast in this way.

3.1.4 Forecast load traces for the total (large) load for Queensland and the generated load for each NEM region

The ACIL Tasman spreadsheet model is then used to grow the half-hourly load traces for:

- The total load for Queensland to match the medium growth forecasts of annual energy, minimum demand and summer and winter peak demands at 50%POE, 10%POE and 90%POE.
- The generated load in each NEM region to match the medium growth forecasts of annual energy, minimum demand and summer and winter peak demands at 50% POE, 10%POE and 90%POE..

The load trace forecasting model uses a non-linear transformation to adjust the recorded load trace to fit the forecast elements using a goal seek method similar to a linear programming solution.

The forecast half-hourly load trace for the total load in Queensland is produced for 2011-12 based on the load trace described above, and the medium growth 10%, 50% and 90% POE forecasts from the Powerlink 2010 APR.

10% and 90% POE load traces are then constructed by replacing the top 400 half hours in the 50% POE load trace with the values from the load traces based on the 10% and 90% POE load forecasts.

A similar approach is used to construct 50%POE, 10%POE and 90%POE as generated load traces for each NEM region used for modelling 50%POE, 10%POE and 90%POE RRPs for use in calculating the cost of energy.

3.1.5 Forecast load traces for directly connected customers for Queensland

The half-hourly load trace for directly connected customers is then increased or decreased by the percentage change in the contribution to summer and winter system demand of the directly connected customers as reported by Powerlink in the relevant APR.

3.1.6 Forecast load traces for NEM (small) load for Queensland

The forecast half-hourly demand trace for retail customers in Queensland (i.e. the NEM load or small load), is then calculated by subtracting the forecast half-hourly demand trace for directly connected customers from the forecast half-hourly demand trace for the total NEM load for Queensland. The resultant forecast is the one that has been used in the calculation of EPC for 2011-12 BRCI.

Table 13 presents the forecast minimum and maximum demand, energy and load factor from this load trace used in the calculation of the 2011-12 BRCI Final Decision.

Table 13 **Maximum and minimum demand (MW), energy (GWh) and load factor (%) – 2011-12 Final Decision and 2010-11 Final Decision**

	Total Load (MW)			Directly Connected (DC) Load (MW)	NEM (small) load (MW)		
	10%POE	50%POE	90%POE		10%POE	50%POE	90%POE
2010-11 Final Decision							
Maximum demand (MW)	9,330	8,866	8,583	1,320	8,192	7,730	7,448
Minimum demand (MW)	3,988	3,988	3,988	804	2,803	2,803	2,803
Energy (GWh)	50,751	50,682	50,641	10,869	39,882	39,813	39,772
Load factor (%)	62.1%	65.3%	67.4%	94.0%	55.6%	58.8%	61.0%
2011-12 Final Decision							
Maximum demand (MW)	9,577	9,104	8,816	1,402	8,457	7,985	7,698
Minimum demand (MW)	4,035	4,035	4,035	1,007	2,798	2,798	2,798
Energy (GWh)	52,345	52,289	52,256	11,273	41,072	41,016	40,983
Load factor (%)	62.39%	65.57%	67.66%	91.79%	55.44%	58.63%	60.77%
% Change							
Maximum demand	2.65%	2.68%	2.71%	6.21%	3.24%	3.30%	3.36%
Minimum demand	1.18%	1.18%	1.18%	25.22%	-0.17%	-0.17%	-0.17%
Energy	3.14%	3.17%	3.19%	3.72%	2.98%	3.02%	3.04%
Load factor	0.47%	0.41%	0.39%	-2.35%	-0.29%	-0.28%	-0.37%

Data source: ACIL Tasman analysis based on Powerlink data

The minimum load for directly connected customers taken from the TNI load traces for the year to 31 March 2011 is noticeably higher than the minimum load for these customers taken from the TNI load traces for the previous year. It has occurred as one or more of the customers were wholly or partially closed for some period during the previous year to 31 March 2010. The increase in minimum load is also partially explained by the increase in the energy and peak load of these customers.

3.2 Simulation market modelling for 2011-12

The market simulation modelling used ACIL Tasman's model of the NEM, PowerMark, and was undertaken using nominal prices for the fuel and other costs so that the resulting RRPs are nominal (that is 2011-12 prices).

PowerMark is used extensively by ACIL Tasman in simulations and sensitivity analyses conducted on behalf of industry clients.

PowerMark effectively replicates the AEMO settlement engine — SPD engine (scheduling, pricing and dispatch). This is achieved through the use of a large-scale LP-based solution incorporating features such as quadratic interconnector loss functions, unit ramp rates, network constraints and dispatchable loads.

The veracity of modelled outcomes relative to the AEMO SPD has been tested and exhibits an extremely close fit.

In accordance with the NEM's market design, the price at any one period is the cost of the next increment of generation in each region (the shadow or dual price within the LP). The LP seeks to minimise the aggregate cost of generation for the market as a whole, whilst meeting regional demand and other network constraints

One of the features of PowerMark is the inclusion of a portfolio optimisation module. This setting allows selected portfolios to seek to maximise net revenue positions (taking into consideration contracts for differences) for each period. These modified generator offers are then resubmitted to the settlement engine to determine prices and dispatch levels. Each period is iterated until a convergence point (based on Nash-Cournot equilibria theory) is found.

This feature results in modelled portfolios structuring their generation offers in an economically rational way.

The assumptions required in order to produce a year of half hourly RRPs are as follows.

- **Electricity consumption**, including energy and maximum demand projections which take into account existing energy conservation measures, distributed renewable generation.
- **New entrant costs**, which are based on new entrant financial models similar to those used in the LRMC modelling.
- **Market supply**, which covers the power stations available to generate in the market and includes assumptions about retirements and new entry as well as planned and unplanned outages over 2011-12.
- **Contract cover**, which sets out ACIL Tasman's assumptions concerning the proportion of energy generated in any period that is covered by swap contracts. This is an important input to the modelling as the proportion of generation that is uncontracted affects the way in which PowerMark models price outcomes. (This is not related to the calculation of contract difference payments undertaken for the small load).

The modelling for 2011-12 shows an outlook in which electricity prices have continued to decline over the past two years following the high prices reached in 2007 and 2008 during the extended drought in eastern Australia.

Hydro generation is now returning to long term average output levels and new capacity has been added to the NEM. Between 2009 and 2012 new capacity added or scheduled amounts to 4,500MW, including the commissioning of Colongra, Eraring expansion, Tallawarra, Uranquinty, Braemar Two, Condamine, Darling Downs, Yarwun, Quarantine expansion, Tamar Valley, Bogong and Mortlake between 2009 and 2012.

Table 14 shows the quarterly average (time weighted) RRPs from the market modelling for the 2011-12 BRCI Final Decision. Settlement has been modelled for three load scenarios – the 10%POE, the 50%POE and the 90%POE.

Table 14 **ACIL Tasman quarterly RRPs– 2011-12 Final Decision ($/MWh)**

	10%POE	50%POE	90%POE
Q3 2011	$57.60	$44.31	$39.17
Q4 2011	$23.95	$23.72	$23.70
Q1 2012	$59.11	$39.30	$26.33
Q2 2012	$32.64	$29.83	$29.57
Annual average	$43.27	$34.28	$29.71

Note, the annual RRP is a time weighted average of the individual quarters.

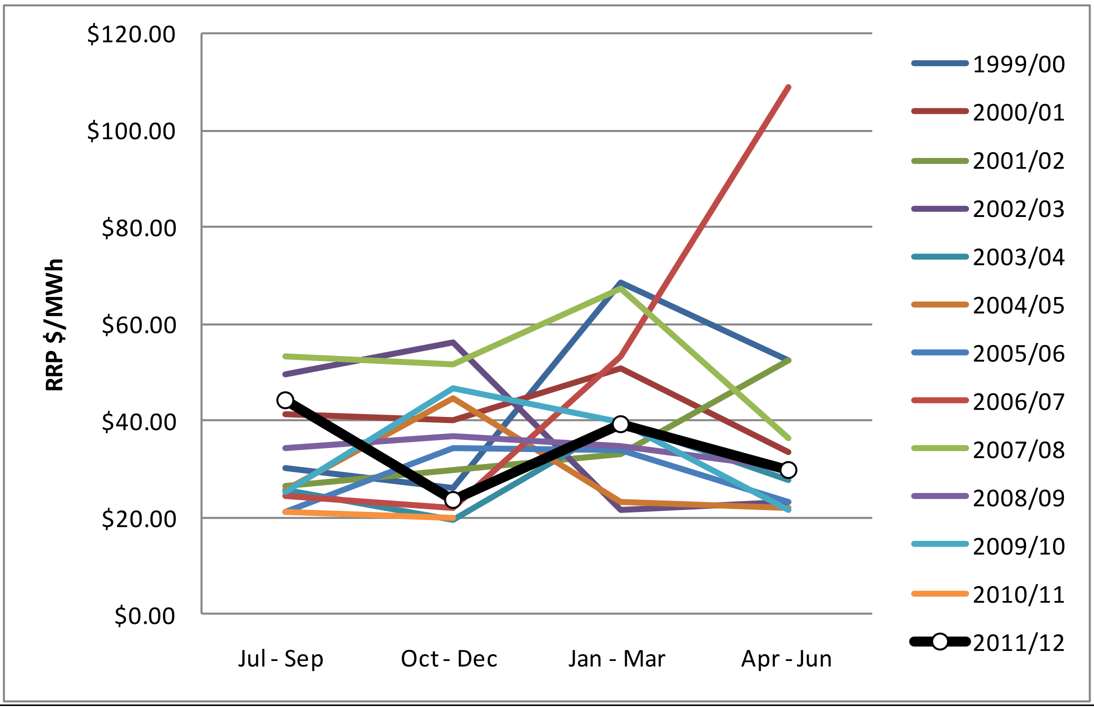
Data source: ACIL Tasman PowerMark modelling

On initial observation, Q32011 prices appear high relative to the other quarters. This is mainly due to certain features of the load trace used to model pool prices in 2011-12, namely:

- a winter load trace which was close to average
- summer demand noticeably lower than average with mild wet conditions

The quarterly pattern of prices used for the 2011-12 BRCI Final Decision is compared with past quarterly patterns in Figure 7. It shows that there has been a significant variation in the quarterly pattern of prices in the past and that, while no other financial year has recorded its highest price in Q3 as does the forecast for 2011-12, the patterns of high winter prices relative to summer, as in the forecast, have been recorded in 2002-03 and 2008-09. It also shows that forecast quarterly prices for 2011-12 are within the past quarterly price range and in ACIL Tasman's view are consistent with the projections of the of the load traces and generation capacities involved.

Figure 7 **Quarterly Queensland RRP for 2011-12 compared with past quarters ($/MWh)**



Source: ACIL Tasman analysis of AEMO load data

The quarterly RRP changes between the Final Decision for the 2010-11 BRCI and the Final Decision for the 2011-12 BRCI are shown in Table 15. It shows that the most significant change occurs in the December quarter in 2011, where prices are lower by around $46/MWh in the 10%POE, $21/MWh in the 50%POE, and $10/MWh in the 90%POE. This is due to a lower and less peaky load trace in the December quarter 2010, reflecting the mild wet conditions in this quarter compared to the December quarter 2009.

The recent weather events (i.e. the floods and cyclone) in the March quarter 2011 have not significantly affected the load trace for the quarter and hence nave not noticeably affected prices in the quarter.

Table 15 **Change in quarterly RRPs between 2010-11 Final Decision and the 2011-12 Final Decision ($/MWh)**

	10%POE	50%POE	90%POE
Q3	$22.01	$9.86	$7.50
Q4	-$46.12	-$21.37	-$10.95
Q1	$1.58	$2.73	-$5.01
Q2	$1.09	-$0.23	$1.51
Annual average	-$5.42	-$2.29	-$1.73

Data source: ACIL Tasman PowerMark modelling

The changes in the RRPs between 2010-11 and 2011-12 are largely due to the load traces used in the modelling which are based in the year to March 2010 and year to march 2011 respectively. Figure 8 compares quarterly load duration curves for 2010-11 Final Decision and 2011-12 Final Decision.

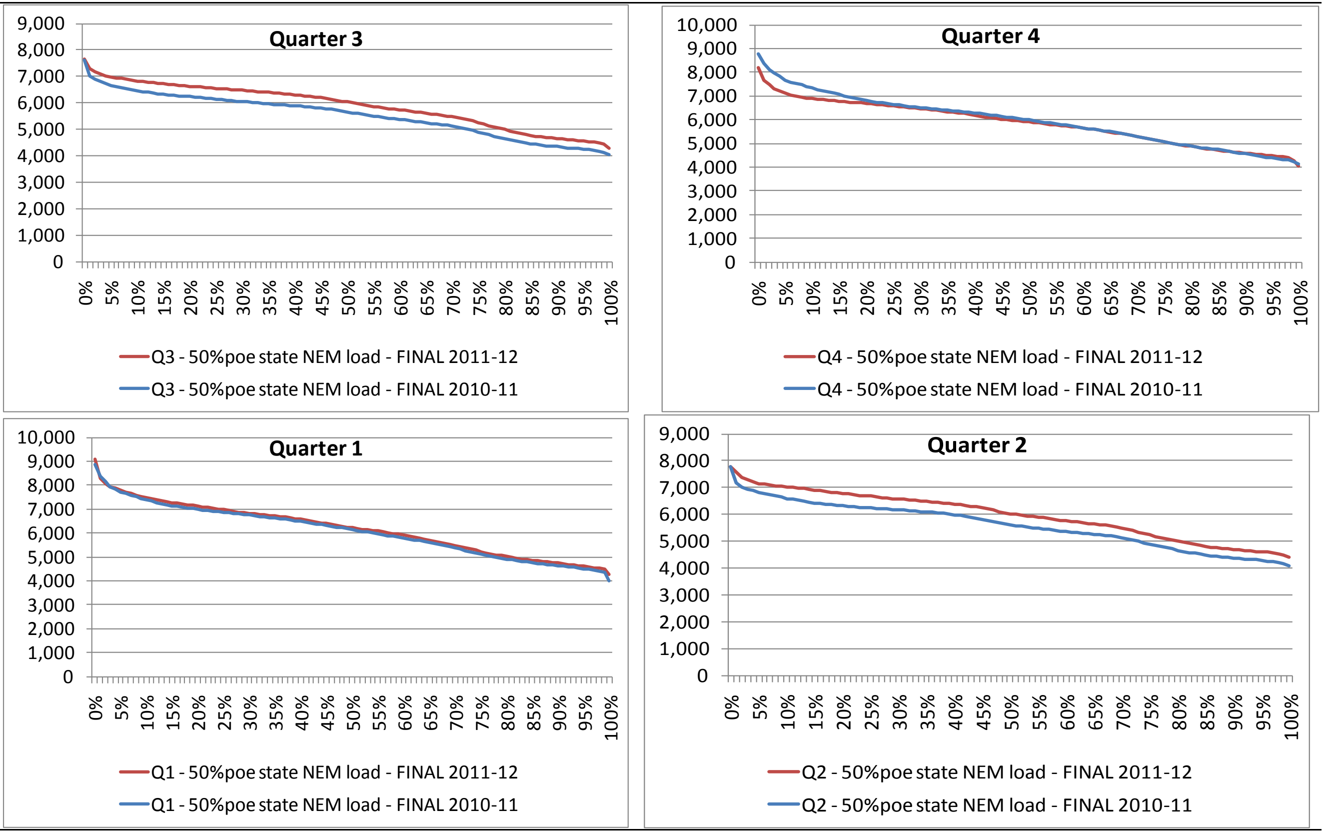
The increase in Q3 price is due to higher loads, as shown in the first graph in Figure 2. Peak load was also higher in this quarter. The higher Q3 2011 RRP used in the 2011-12 Final Decision was also partially caused by a small number of price spikes occurring when planned and random forced plant outages have coincided with the higher loads during the quarter. Price spikes are a normal part of the NEM.

The large fall in the Q4 price from 2009 to 2010 is explained by a lower and less peaky load as shown in the second graph in Figure 2.

Q1 prices changed slightly, which corresponds with the small difference in loads in Q1, as shown in the third graph in Figure 2.

Q2 as shown in Table 15 prices changed only slightly, despite higher average loads in this quarter, but with similar peak load, as shown in fourth graph of Figure 2. However, observation of the half hourly price data revealed that there were no significant price spikes during this quarter.

Figure 8 **Load duration curves, by quarter – 2011-12 Final Decision vs. 2010-11 Final Decision**



Source: ACIL Tasman analysis of AEMO load data

3.3 Contracting strategy and prices

ACIL Tasman has followed the contracting methodology used in last year's calculation of the EPC for the 2010-11 BRCI, which was developed by CRA for QCA in previous calculations of the BRCI. The methodology has been discussed with stakeholders and appears to have become broadly agreed.

The strategy assumes that the retailer's objective is to purchase contracts that match its load as closely as possible so that it is not exposed to the spot market during peak periods and it is not over-contracted during off-peak periods.

The following criteria are used each quarter to purchase hedge contracts for the Queensland small load is

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

The strategy requires that a retailer represented in the calculation of the BRCI would spread its purchases of energy contracts for each tariff year evenly over a period of two years preceding the year in question, in advance of the tariff year for which the energy is being hedged. This results in contracts being purchased evenly over the period.

We have assumed therefore, in common with previous years that for calculation of the EPC contracts are purchased evenly over the period 1 July 2009 to 31 March 2011[10]. That is the using all the price data available in the two years preceding the commencement of the BRCI year, which in the case of the BRCI calculations is 21 months of data.

Table 16 shows estimated quarterly swap and cap contract volumes purchased for 2011-12 under this strategy used for the Final Decision.

Table 16 **Quarterly swap and cap contract volumes – 2011-12 Final Decision compared to 2010-11 Final Decision (MW)**

	2010-11 Final Decision			2011-12 Final Decision			Percent change		
	Flat contract volume	Peak contract volume	Cap contract volume	Flat contract volume	Peak contract volume	Cap contract volume	Flat contract volume	Peak contract volume	Cap contract volume
Q3	4,276	1,172	1,331	4,570	1,181	1,022	6.9%	0.8%	-23.2%
Q4	4,646	1,854	1,413	4,514	1,374	1,391	-2.8%	-25.9%	-1.5%
Q1	4,840	1,711	1,565	4,867	1,755	1,762	0.6%	2.6%	12.6%
Q2	4,275	1,379	1,244	4,634	1,289	938	8.4%	-6.5%	-24.6%

The similarities and differences between the two sets of contract volumes for each quarter are due to differences in the load traces used in the two calculations. The load trace used in this Final Decision for 2011-12 covers the 12 months to 31 March 2011 while the load trace used in the Final Decision for the 2010-11 BRCI covered the 12 months to 31 March 2010. The most noticeable difference is in Q4 2010 (used in the 2011-12 BRCI Final decision), where the load was lower and less peaky compared to Q4 2009(used in the 2010-11 BRCI Final decision). As a consequence flat, peak and cap contract volumes are lower in the 2011-12 BRCI Final Decision.

[10] This timeline is slightly shorter for Q1 2012 and Q2 2012 cap contracts, which began trading from 1 April 2010.

The lowering of the cap volumes in Q3 and Q2 is because the amplitude of the load traces, not necessarily the absolute size of the peak, is lower in these quarters for the 2011-12 BRCI Final Decision than in the 2010-11BRCI Final Decision thereby reducing the need for cap contracts in the 2011-12 BRCI Final Decision compared with the 2010-11 BRCI Final Decision. With less amplitude in the load trace more of the load is covered by flat and peak contracts leaving less to be covered by cap contracts.

3.3.1 Contract prices

The cost of the swap and cap contracts has been estimated under the assumption that the retailer spreads its purchases of contracts evenly over the period from 1 July 2009 to 31 March 2011.

Data from d-cypha Trade was used to estimate the cost of electricity swap and cap contracts. Contract prices were estimated using the average of daily settlement prices from 1 July 2009 up until 31 March 2011, which is the cut-off date for market data for the Final Decision [11].

Table 17 shows estimated quarterly swap and cap contract prices for 2011-12 compared to those used in the Final Decision for the 2010-11 BRCI. The flat and peak swap contracts used in this Final Decision for the 2011-12 BRCI are consistently lower than the corresponding contract prices used in the Final Decision for the 2010-11 BRCI. Flat contract prices have fallen most and the contract prices in Q1, traditionally the high priced time of year in the NEM, have also fallen significantly.

These falls in contract price would be reflecting a view that the market spot prices will follow similar trends. It can be seen that the fall in contract prices is generally consistent with a decline in the RRP from 2011-11 to 2011-12 from ACIL Tasman's modelling (see Table 15)

[11] This timeline is slightly shorter for Q1 2012 and Q2 2012 cap contracts, which began trading from 1 April 2010.

Table 17 **Quarterly swap and cap contract prices – 2011-12 Final Decision compared to the 2010-11 Final Decision ($/MWh)**

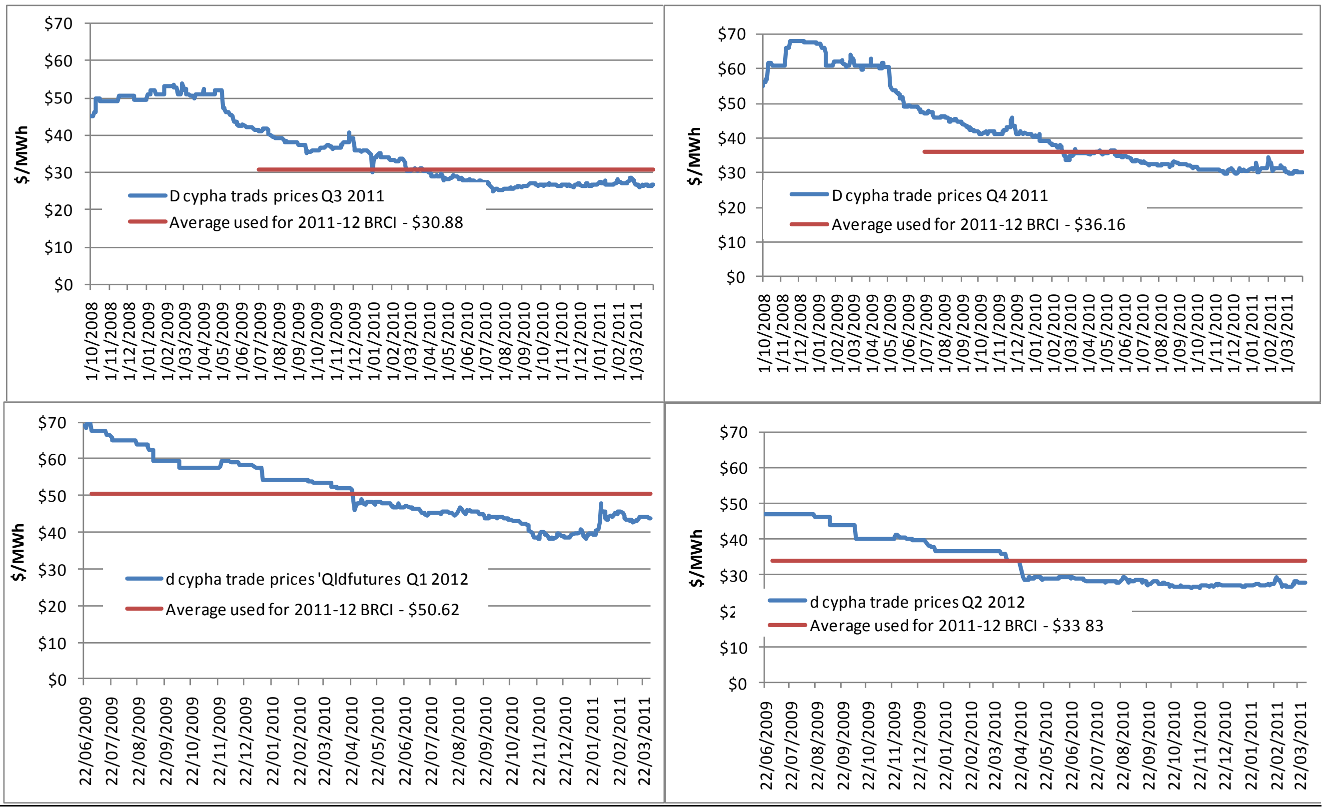
	2010-11 Final Decision			2011-12 Final Decision			Percent change		
	Flat contract price	Peak contract price	Cap contract price	Flat contract price	Peak contract price	Cap contract price	Flat contract price	Peak contract price	Cap contract price
Q3	$36.92	$50.47	$4.58	$30.88	$44.56	$3.98	-16.37%	-11.71%	-13.10%
Q4	$45.12	$66.18	$10.06	$36.16	$56.66	$9.16	-19.86%	-14.38%	-8.94%
Q1	$66.80	$110.39	$25.21	$50.62	$90.30	$17.86	-24.23%	-18.20%	-29.14%
Q2	$39.03	$47.59	$4.56	$33.83	$46.91	$3.13	-13.33%	-1.43%	-31.31%

Data source: ACIL Tasman analysis using d-cyphaTrade data

Forward contract prices have been falling since the high priced period from 2007 to 2009, which was caused by the prolonged drought in eastern Australia leading to shortages of water for cooling in some thermal power stations and generation water in hydro stations. The weather patterns in eastern Australia over this period tended to produce high summer temperatures which also lead to high electricity prices.

Table 17 shows the downward trend in Queensland flat contract prices in recent years and the average quarterly flat contract prices used in calculating the 2011-12 BRCI Final Decision.

Figure 9 **Flat contract price trends in Queensland and the average quarterly prices used for the 2011-12 BRCI Final Decision**



Source: ACIL Tasman analysis d cypha trade data

3.4 Settlement

In the settlement process the half hourly prices from the 2011-12 market simulation are brought together with the half hourly loads for the small load and the contracting prices and quantities for each half hour of the year in a spreadsheet model to provide a projection of the cost of purchasing energy for the small load in 2011-12.

As described in the section above the Queensland load data used to calculate the cost of purchasing energy is measured at the Transmission Node. In order to reflect transmission losses in the final energy purchase cost, the average loss factor (ALF) is applied to the cost estimate (in $/MWh).

From Table 2.7, page 26 of the Powerlink 2010 APR we took the transmission losses for 2011-12 (2,009GWh) and divided by the sent-out energy (54,297GWh), to get a loss factor of 3.7%. This is the same method as used in our calculation for the 2010-11 BRCI.

The results for 2011-12 are shown in Table 18. There are a number of changes between our calculation for the Final Decision for the 2011-12 BRCI and our Final Decision for the 2010-11 BRCI. The key ones are:

- the RRPs are lower overall
- flat contract volumes are generally higher
- peak and cap contract volumes are generally lower
- flat, peak and cap contract prices are noticeably lower.

This has resulted in:

- significantly lower pool costs
- increased swap difference payments
- a lower EPC in 2011-12.

Table 19 shows the estimated cost of purchasing energy for the 2011-12 BRCI Final Decision.

Table 18 **Contract settlement for the 10%, 50% and 90% POE for 2011-12 Final Decision and the 2010-11 Final Decision**

	10% POE	50% POE	90% POE
2011-12 Final Decision			
Total MWh	41,072,035	41,015,814	40,982,719
Total pool costs $	$2,158,912,863	$1,595,063,470	$1,322,998,723
Swap difference payments $	-$291,469,164	$199,823,569	$454,400,828
Cap premiums $	$111,529,763	$111,529,763	$111,529,763
Cap payments $	-$167,029,879	-$70,580,513	-$17,800,587
Total energy purchase cost $	$1,811,943,583	$1,835,836,288	$1,871,128,726
Total energy purchase cost $/MWh	$44.12	$44.76	$45.66
Total energy purchase cost (including ALF) $/MWh	$45.75	$46.42	$47.35
2010-11 Final Decision			
Total MWh	39,881,858	39,812,567	39,771,882
Total pool costs $	$2,518,466,674	$1,711,618,772	$1,402,837,178
Swap difference payments $	-$196,627,841	$490,449,318	$772,597,454
Cap premiums $	$142,482,345	$142,482,345	$142,482,345
Cap payments $	-$238,222,156	-$100,752,308	-$46,127,321
Total energy purchase cost $	$2,226,099,022	$2,243,798,127	$2,271,789,655
Total energy purchase cost $/MWh	$55.82	$56.36	$57.12
Total energy purchase cost (including ALF) $/MWh	$57.88	$58.44	$59.23
Difference 2011-12 minus 2010-11			
Total MWh	1,190,177	1,203,247	1,210,837
Total pool costs $	-$359,553,811	-$116,555,302	-$79,838,455
Swap difference payments $	-$94,841,323	-$290,625,749	-$318,196,626
Cap premiums $	-$30,952,582	-$30,952,582	-$30,952,582
Cap payments $	$71,192,277	$30,171,795	$28,326,734
Total energy purchase cost $	-$414,155,439	-$407,961,839	-$400,660,929
Total energy purchase cost $/MWh	-$11.70	-$11.60	-$11.46
Total energy purchase cost (including ALF) $/MWh	-$12.13	-$12.02	-$11.88

The weighted energy purchase cost in 2011-12 is **$46.50/MWh**. This is $12.02/MWh less than the EPC estimated in our Final Decision for the 2010-11 BRCI.

Table 19 **Energy purchase costs for 2011-12, scenario results, weightings and weighted values ($/MWh)**

	Scenario weighting	Final Decision 2011-12	Final Decision 2010-11	Change
Energy purchase costs ($/MWh) - 10POE	30.40%	$45.75	$57.88	-$12.13
Energy purchase costs ($/MWh) - 50POE	39.20%	$46.42	$58.44	-$12.03
Energy purchase costs ($/MWh) - 90POE	30.40%	$47.35	$59.23	-$11.89
Energy purchase costs ($/MWh) - Weighted		**$46.50**	**$58.51**	**-$12.02**

Data source: ACIL Tasman analysis

The key factors causing the fall in the EPC for 2011-12 BRCI Final Decision are:

- the significant reduction in contract prices (see Table 17).
- lower pool prices (see Table 15).
- a flatter NEM load for Queensland (the small load) giving rise to generally less of the more expensive peak and cap contracts and more of the lower priced flat contracts (see Table 16).

4 Other energy costs

Other energy costs include:

- Enhanced Renewable Energy Target (RET) encompassing:
  - Large-scale Renewable Energy Target (LRET)
  - Small-scale Renewable Energy Scheme (SRES)
- Queensland Gas Scheme
- NEM fees
- Ancillary services

ACIL Tasman has used as near as possible the same methodology to estimate other energy costs for the 2011-12 BRCI Final Decision as applied in previous BRCIs, However there have been some modifications to incorporate changes to the RET scheme and to more closely reflect the market value of the Gas Electricity Certificates (GECs).

The approach for estimating the cost of NEM fees and Ancillary Services has stayed as close as possible to the previous approach to these calculations given the need to maintain a consistent methodology.

The basic approach to estimating the cost of the enhanced Renewable Energy Target (RET), while similar to previous BRCIs, has had to be modified to incorporate the split of the scheme into LRET and SRES from 1 January 2011. More details of the methodology used for estimating the costs of the enhanced RET scheme (LRET and SRES) are provided in Section 4.1.

The estimated cost of the Queensland Gas Scheme has been approached in a different way to previous years. The new approach incorporates the market price of GECs rather than the use of the penalty price. As a result of this change, our previous estimate of the cost of GECs for 2010-11 as contained in our final report for the 2010-11 BRCI has been revised for consistency. More details of the revised approach are provided in Section 4.2.

4.1 Renewable Energy Target scheme

As of 1 January 2011, the enhanced Renewable Energy Target (RET) will see the split of the scheme into two parts: the Large-scale Renewable Energy Target (LRET), and the Small-scale Renewable Energy Scheme (SRES). From 1 January 2011, liable parties will be 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[12]
- Office of the Renewable Energy Regulator (ORER) estimated Renewable Power Percentage (RPP) for 2011 of 5.62%
- Adjusted LRET target for 2012 of 16,338 GWh as published by ORER
- ACIL Tasman estimate for total liable energy for 2012 of 185,672 GWh (based on ORER earlier estimate of the Small-scale Technology Percentage (STP) for 2012 of 16.75% based on 31.1 million Small-scale Technology Certificates STCs)
- ORER estimate for 2011 STP of 14.8%
- ACIL Tasman estimate for 2012 STP of 9%[13]

4.1.1 LRET

In attempting to estimate the costs faced by retailers complying with LRET (and more importantly, the changes in the cost of complying with LRET) through the BRCI, the most transparent approach is to use market data when it is available. ACIL Tasman believes that the market price of Large-scale Generation Certificates (LGCs) most accurately reflects the short-term cost of LGCs to retailers.

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 **$41.66/MWh for 2011** and **$40.64/MWh for 2012.**

The AFMA weekly LGC prices have been averaged over the following periods, consistent with the averaging methodology from previous BRCI decisions:

- 2011 is based on prices from 22 January 2009 to 31 Mar 2011 (113 weeks)
- 2012 is based on prices from 20 January 2010 to 31 Mar 2011 (63 weeks)

The 25% increase in LGC price since January 2011 referred to in submissions to the 2011-12 BRCI Draft Decision by Origin and TRUenergy, which is evident in the AFMA price data, does not in ACIL Tasman's view represent a 25% increase to the cost of retailers of complying with the LRET in 2011-12. This is because the majority of LGCs in the retailer's portfolio will have been acquired previously at the lower price.

ACIL Tasman has used the ORER adjusted LRET target for 2012 of 16,338GWh and ACIL Tasman's estimated total liable energy of 185,672GWh for that year to arrive at the estimate of 8.8% for the 2012 RPP. The

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[12] AFMA data includes weekly settlement prices to 31 March 2011, which is the cut-off date for all relevant market-based data used in the Final Report for the 2011-12 BRCI.

[13] This estimate incorporates the recent adjustment to the Solar Credits multiplier, announced on 5 May 2011, which reduces the multiplier to 3 rather than 4 on 1 July 2011.

185,672GWh estimate for 2012 of total liable energy has been calculated by ACIL Tasman from data on STCs in 2012 published by ORER. The ORER published an estimate of 31.1 million STCs for an STP of 16.75% which implies a total liable energy of 185,672GWh (i.e. 31,100/0.1675=185,672). ACIL Tasman understands that the total liable energy has been falling because the partial exempted energy has been increasing. . Using this approach means that it is unnecessary to estimate PECs.

Table 20 below shows the parameters ACIL Tasman has used to calculate the 2012 RPP.

Table 20 **Elements of the 2012 RPP estimate**

Calendar Year	Required GWh of renewable source electricity	Total liable energy GWh	Renewable Power Percentage (RPP)
2010	**12,500**	208,978	**5.98%**
2011	**10,600**	188,610	**5.62%**
2012	**16,338**	185,672	8.80% [a]

[a] **Bold** numbers are published by ORER and non bold numbers are ACIL Tasman estimates

Data source: ORER, ACIL Tasman analysis

Based on this approach, we estimate the cost of complying with the LRET scheme to be $2.96/MWh in 2011-12 as shown in Table 21.

Table 21 **Estimated cost of LRET for 2011-12 BRCI Final Decision**

	2011	2012	Cost of LRET for 2011-12 BRCI Final Decision
RPP %	5.62%	8.80%	
Adjusted target GWh	10,600	16,338	
Average LGC price $/MWh	$41.66	$40.64	
Cost of LRET	**$2.34**	**$3.58**	**$2.96**

Data source: ORER, AFMA, ACIL Tasman analysis

4.1.2 SRES

For the estimation of the cost of SRES, we have used the ORER clearing house STC price of $40/MWh in 2011 and 2012. This price is then multiplied by the STP to calculate the cost of compliance with the SRES in $/MWh.

ACIL Tasman has used the published STP for 2011 of 14.8% and its own estimate for the 2012 STP of 9%, as explained in more detail below. The estimate used for the 2011-12 BRCI Final Decision is then taken as the average of the 2011 and 2012 results.

On 5 May 2011the Commonwealth Government announced that the Solar Credits multiplier used in determining the size of the government grant for small-scale generation particularly PVs will be adjusted to 3 rather than 4 from 1 July 2011 and to 2 rather than 3 from 1 July 2012. The lower multiplier has two effects:

- firstly, it directly reduces the number of STCs that are created
- secondly, it reduces the number of installations, because under a lower multiplier, financial returns to potential solar PV system owners in Australia are reduced. For example, a reduction of one in the Solar Credits multiplier reduces the initial income from a 1.5kW PV by $1240 in Queensland.

In addition the NSW Government has decided remove its PV feed-in tariff for new PV installations and the WA PV feed-in tariff has been halved. These can be expected to have a noticeable impact on the rate of new PV installations during 2012.

Our modelling suggests that the number of STCs created in 2012 will be around 16.7 million under the lower multiplier and reduced feed in tariffs. This estimate is based on a reduced of PV installations and assumes that no excess STCs will be created in 2011to be accounted in 2012. The 16.7 million STC estimate for 2012 compares an earlier ACIL Tasman estimate of 16.9 million STCs for 2013[14] which then had the same Solar Credit multipliers as now apply to 2012. Using estimated liable energy in 2012 of 185,672 GWh as discussed in Section 4.1.1 above, the resultant STP estimate for 2012 is 9%.

Based on this approach, we estimate the cost of complying with the SRES to be $4.76/MWh in 2011-12.

Table 22 **Estimated cost of SRES – 2011-12**

	2011	2012	Cost of SRES Final report 2011-12
STP %	14.8%	9%	
STC clearing house price $/MWh	$40.00	$40.00	
Cost of SRES	**$5.92**	**$3.60**	**$4.76**

Data source: ORER, AFMA, ACIL Tasman analysis

[14] See Table 14 in the ACIL Tasman report to ORER of 15 November 2010 entitled, "Small-scale Technology Certificates Data Modelling" at http://www.orer.gov.au/publications/pubs/acil-tasman-stc-modellingreport.pdf

By combining the LRET and SRES costs for each year and taking the average of costs in 2011 and 2012, results in a total cost of both schemes of $7.72/MWh.

Table 23 shows the estimated combined cost of LRET and SRES for the 2011-12 BRCI Final Decision compared with the estimated cost of RET in final report for the 2010-11 BRCI.

Table 23 **Estimated combined cost of LRET and SRES ($/MWh)**

2010-11			2011-12		
2010	2011	Cost of RET Final Report 2010-11	2011	2012	Cost of LRET and SRES Final Report 2011-12
$2.85	$3.25	**$3.05**	$8.26	$7.18	**$7.72**

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

4.2 Queensland Gas Scheme

In previous calculations of the energy cost component of the BRCI by CRA and by ACIL Tasman in 2010-11, the change in the cost of complying with the Queensland Gas Scheme has been calculated as the product of the prescribed percentage (proportion of retail sales that must be covered by a Gas Electricity Certificate, GEC) and the tax adjusted level of the penalty.

However, the Scheme has a high rate of compliance and the penalty is rarely applied. ACIL Tasman's view is that where a market price for inputs to the calculation of retailers' Energy Purchase Costs can be sourced reliably and consistently each year it should provide the best guide for year on year changes in costs. Annual movements in the cost of complying with the Scheme will therefore be better reflected by year on year changes in the market price of GECs than by the penalty.

In its submission to the 2011-12 Draft Decision Origin questioned the proportion of GEC liability covered by the AFMA price data used. The calculation of the GEC price for the BRCI assumes that the GECs are purchased evenly in the 2.5 years prior to the beginning of the year being estimated. The volume traded is not an input to the calculation of the GEC price just as the volume of swap and cap contracts or LGCs are not taken into consideration but assumed to be even over the price averaging period. A more accurate methodology would be to weight the weekly prices by the volumes traded however these volumes are not available and in any case retailers' weighted GEC prices would vary considerably depending on the pattern of purchases. The methodology assuming even purchases is therefore an approximation of the actual GEC price faced by retailers but is considered adequate for the purposes of calculating the cost of GECs for the BRCI.

Table 24 **Estimated cost of Queensland Gas Scheme using AFMA data, $/MWh**

	2010-11	2011-12
Price of GECs from AFMA data	$8.57	$4.37
Prescribed percentage	15%	15%
Total cost of Queensland Gas Scheme	**$1.29**	**$0.65**

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

ACIL Tasman has calculated GEC market prices for 2010-11 and 2011-12 by averaging weekly settlement prices leading up to the commencement of the GEC liable year (calendar year). The AFMA data on GEC prices is available from 1 July 2007 and ACIL Tasman has used data from this date. For example, the GEC price estimate for 2010 is the average of weekly settlement prices from 1 July 2007 to 31 December 2009. Calendar years are used as the requirement for liable parties (e.g. energy retailers) to surrender the prescribed amount of GECs is calculated on a calendar year basis. The financial year GEC price estimates are found by averaging the two calendar years.

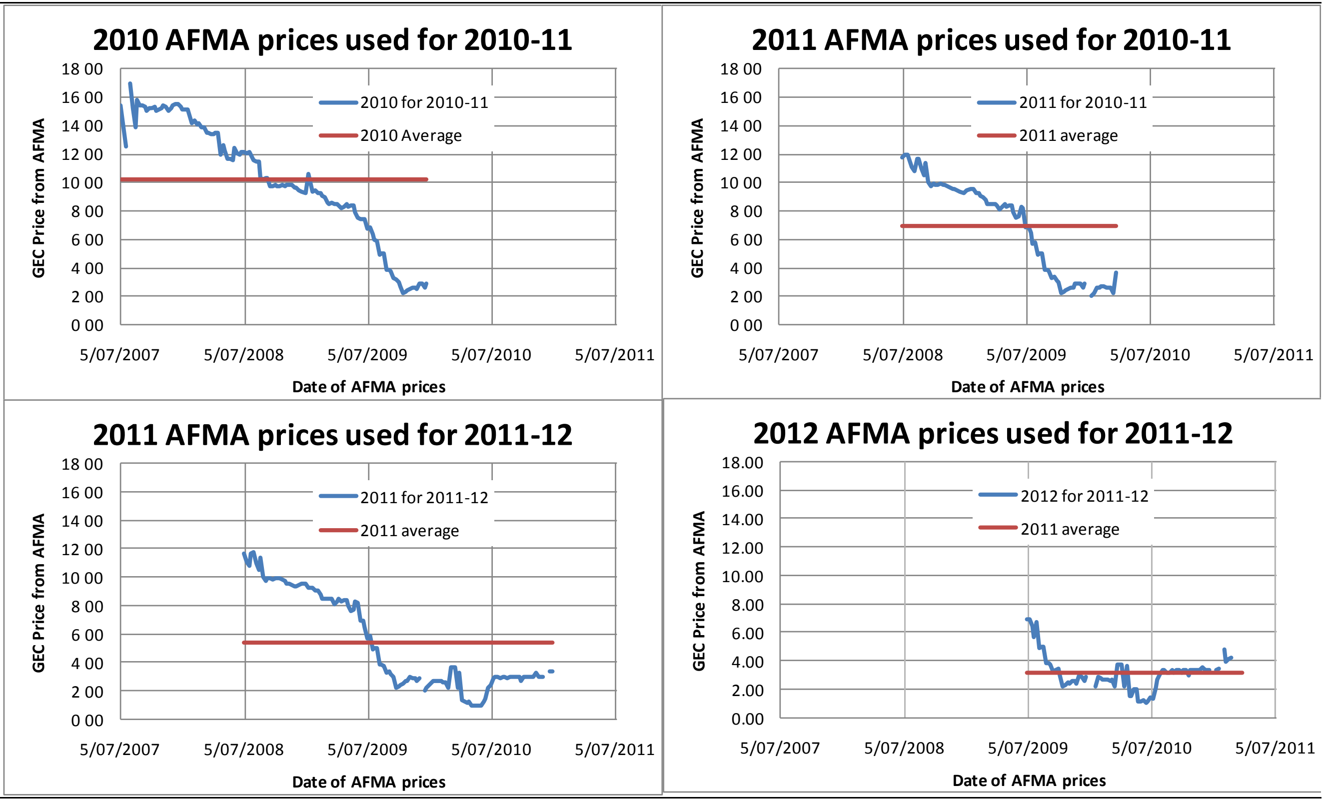
The average GEC price for 2010-11and 2011-12 have been calculated using the same period of prices in the lead up to the calendar year being estimated. The cut-off date for the AFMA data used for the 2011-12 BRCI Final Decision is 31 March 2011. Similarly a cut-off date of 31 March 2010was used for recalculating the 2010-11 GEC price estimate. This allows calculation of the movement in GEC costs between 2010-11 and 2011-12 on a consistent basis.

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

- 2010 for 2010-11 - from 1 July 2007 to 31 Dec 2009 (127 weeks)
- 2011 for 2010-11- from 1 July 2008 to 31 Mar 2010 (88 weeks)
- 2011 for 2011-12- from 1July 2008 to 31 Dec 2010 (128 weeks)
- 2012 for 2011-12- from 1 July 2009 to 31 Mar 2011 (91 weeks)

The AFMA prices used are shown in Figure 10. The large fall in prices is associated with the market becoming over supplied.

Figure 10 **AFMA market prices used in determining the GEC prices for 2010-11 and 2011-12**



Data source: AFMA market data

4.2.1 The AFMA data

AFMA produces weekly prices for environmental products (RECs, NGACs and GECs) based on weekly price data collected from various contributors (mostly retailers). In total, there are around 14 contributors to environmental products curves although not all of these contribute to the GEC price data.

The data is collected each week through a telephone interview with a nominated person in each of the retailers. There are a significant number of weeks when no price is provided because there have been very few or zero trades. Since November 2009, the maximum number of contributors to the GEC price curve has been 5 per week. The number of contributions in any given week is sometimes reduced due to the exclusion of price outliers (i.e. AFMA exclude prices that are outside one standard deviation from the mean).

AFMA have collected the data in the same way since the GEC liability arose and there are no indications that they will stop collecting the data or change the fairly simple survey approach they have now.

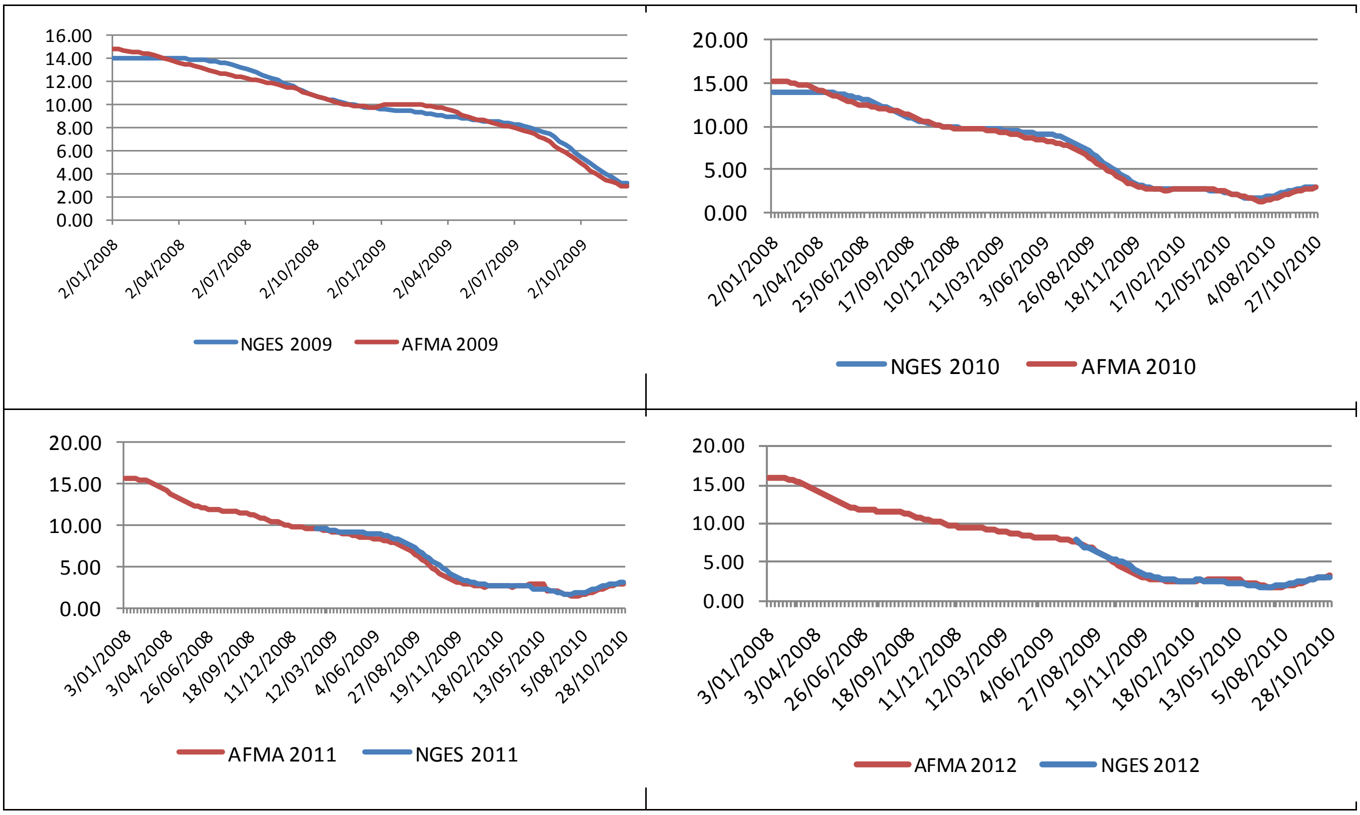
Concerns have been raised about using the AFMA data as a reliable guide to GEC market prices. AFMA present the data as the result of a telephone survey with a relatively small number of respondents.

In order to corroborate the AFMA data we have sought data on forward GEC prices from Nextgen, a broker providing energy products to wholesalers and retailers in the NEM, including so-called environmental products such as RECs and GECs.

AFMA and Nextgen GEC forward prices have been compared over the period January 2008 to October 2010. Figure 11 shows the comparison between the 90 day moving average price of GEC prices for 2009, 2010, 2011 and 2012 from AFMA and Nextgen. Nextgen prices for 2011 are only available from February 2009 and for 2012 from July 2009.

The annual graphs of forward prices show a strong similarity between the two data sources. They follow a similar path throughout each year and there is no indication that one has consistently higher or lower prices than the other. The average year on year differences between the two sources are also very similar and result in a similar estimate for the change in GEC costs between 2010-11 and 2011-12 (Table 24).

Figure 11 **Comparison of 90 day moving average forward prices of GECs for 2009 to 2012 sourced from AFMA and Nextgen**



Data source: AFMA and Nextgen, shown as NGES in the figure.

The above provides a reasonable confirmation that AFMA is a reasonable source of GEC prices.

AGL stated in its submission to the 2011-12 Draft Decision that the movement in the GEC price is better represented by a longer term view of the market price (e.g. 4 year average). However, there is insufficient market data to be able to calculate the cost of GECs in 2010-11 and 2011-12 using the extended averaging period, because AFMA GEC price data is only available from July 2007. ACIL Tasman used the all available GEC price data from July 2007 in calculating the movement in GEC costs from 2010-11 to 2011-12

The use of the AFMA market price data has also been criticised on the basis that it is unreliable because little or no GECs are being currently traded. However, the low prices currently being bid or offered in the market correctly reflect an oversupplied GEC market. Furthermore this is consistent with the approach used in calculating market prices for swap and cap contracts and LGCs which do not weight prices by volume.

4.3 NEM fees

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

ACIL Tasman has referred to AEMO's draft budget NEM fees for 2011-12 to calculate the estimate for 2011-12.

Table 25 compares the NEM fees estimates in the 2010-11 BRCI final decision and the estimate for the 2011-12 BRCI Final Decision.

ACIL Tasman's estimates for NEM fees are provided in Table 25 which shows total NEM fees for 2011-12 have increased by $0.05/MWh or around 15%.

Table 25 **Estimated NEM fees ($/MWh)**

Cost category	Final Decision 2010-11	Final Decision 2011-12	% change
Market participant fees	$0.28	$0.33	18%
FRC fees	$0.06	$0.06	0%
Total NEM fees	**$0.34**	**$0.39**	**15%**

Data source: ACIL Tasman analysis based on the AEMO draft budget 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 31st March 2011 for this report for the

2011-12 BRCI Final Decision), it is estimated that the cost of ancillary services will be $0.45/MWh for 2011-12.. This is 15% higher than the $0.39/MWh in the 2010-11 BRCI.Final Decision.Table 26 compares the Ancillary Services charges estimates included in the for the 2010-11 and 2011-12 BRCI Final Decisions.

Table 26 **Estimated ancillary services charges ($/MWh)**

	Final Decision 2010-11	Final Decision 2011-12	% change
Ancillary services	$0.39	$0.45	15%

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

4.5 Summary of other energy costs

In summary, other energy costs for the 2011-12 BRCI are estimated to be $9.11/MWh, an increase of 83% compared to the final report for the 2010-11 BRCI. Table 27 compares the other energy cost estimates to be used in this report with the estimates used in the final report for the 2010-11 BRCI.

Table 27 **Summary of other energy costs ($/MWh)**

Cost category	Final Report 2010-11	Final Report 2011-12	% change
Renewable Energy Target	$3.05	$7.72	153%
Queensland Gas Scheme	$1.29	$0.65	-49%
NEM fees	$0.34	$0.39	15%
Ancillary services	$0.39	$0.45	13%
Total other energy costs	**$5.07**	**$9.21**	**82%**

Data source: ACIL Tasman analysis based on AFMA and AEMO data.

A Electricity market modelling for 2011-12

This Appendix provides the input data and assumptions for the *PowerMark* electricity market modelling used to provide RRPs for each half hour in 2011-12. It begins by setting out the supply side inputs from ACIL Tasman's generator database, assumed additions and withdrawals of plant, short run marginal costs, heat rates, loss factors, offer strategies, contract cover assumptions and plant availability.

A.1 Supply

A.1.1 Introduction

When taken together with the electricity demand forecast, the assumptions regarding plant additions and retirements will determine the supply-demand balance and are critical to the modelling results.

A.1.2 Initial supply settings

Table 28 to Table 32 outline generator characteristics in terms of portfolio, generator type, capacity and on-off dates for existing and committed plant.

Table 28 **Initial setting for existing and committed plant, NSW**

Region	Generator	DUID	From Date	To Date	Gen Type	Fuel	Unit Size (MW)	Min Gen (MW)	Contract Cover (MW)	Aux (%)	Thermal efficiency (HHV sent-out, %)	Emission factor (t CO2/GJ)	Emission factor (t CO2/MWh)	Var O&M (2009 $/MWh, sent-out)
NSW1	Bayswater	BW01	1/01/2012		Steam turbine	Black coal	680	310	490	6.0%	35.9%	0.0902	0.9045	$1.18
NSW1	Bayswater	BW02	1/01/2012		Steam turbine	Black coal	680	310	330	6.0%	35.9%	0.0902	0.9045	$1.18
NSW1	Bayswater	BW03	1/01/2012		Steam turbine	Black coal	680	310	490	6.0%	35.9%	0.0902	0.9045	$1.18
NSW1	Bayswater	BW04	1/01/2012		Steam turbine	Black coal	680	310	330	6.0%	35.9%	0.0902	0.9045	$1.18
NSW1	Bendeela No. 1 Pump	SHPUMP	1/01/2012		Hydro	Hydro	240	0	0	1.0%	100.0%	0.0000	0.0000	$9.23
NSW1	Blowering 1x80MW	BLOWERNG	1/01/2009		Hydro	Hydro	80	20	20	1.0%	100.0%	0.0000	0.0000	$5.13
NSW1	Colongra	CG1	1/01/2012		Gas turbine	Na ural gas	166	0	10	3.0%	32.0%	0.0513	0.5771	$9.98
NSW1	Colongra	CG2	1/01/2012		Gas turbine	Na ural gas	166	0	10	3.0%	32.0%	0.0513	0.5771	$9.98
NSW1	Colongra	CG3	1/01/2012		Gas turbine	Na ural gas	166	0	10	3.0%	32.0%	0.0513	0.5771	$9.98
NSW1	Colongra	CG4	1/01/2012		Gas turbine	Na ural gas	166	0	10	3.0%	32.0%	0.0513	0.5771	$9.98
NSW1	Eraring Power Sta ion 330kv	ER01	1/01/2012		Steam turbine	Black coal	720	210	460	6.5%	35.4%	0.0895	0.9102	$1.18
NSW1	Eraring Power Sta ion 330kv	ER02	1/01/2012		Steam turbine	Black coal	720	210	460	6.5%	35.4%	0.0895	0.9102	$1.18
NSW1	Eraring Power Sta ion 500kv	ER03	1/01/2012		Steam turbine	Black coal	720	210	460	6.5%	35.4%	0.0895	0.9102	$1.18
NSW1	Eraring Power Sta ion 500kv	ER04	1/01/2012		Steam turbine	Black coal	720	210	460	6.5%	35.4%	0.0895	0.9102	$1.18
NSW1	Guthega 2x30MW NSW	GUTHEGANSW1	1/01/2009		Hydro	Hydro	60	0	27	1.0%	100.0%	0.0000	0.0000	$7.18
NSW1	Hume Power Station NSW	HUMENSW	1/01/2009		Hydro	Hydro	29	5	0	1.0%	100.0%	0.0000	0.0000	$6.15
NSW1	Hunter Valley Gas Turbine	HVGTS	1/01/2009		Gas turbine	Fuel oil	50	0	0	3.0%	28.0%	0.0697	0.8961	$9.50
NSW1	Liddell	LD01	1/01/2012		Steam turbine	Black coal	525	250	350	5.0%	33.8%	0.0928	0.9884	$1.18
NSW1	Mt Piper Power Sta ion	MP1	1/01/2012		Steam turbine	Black coal	660	280	280	5.0%	37.0%	0.0874	0.8504	$1.31
NSW1	Mt Piper Power Sta ion	MP2	1/01/2012		Steam turbine	Black coal	660	280	570	5.0%	37.0%	0.0874	0.8504	$1.31
NSW1	Munmorah Power Station	MM3	1/01/2012		Steam turbine	Black coal	300	150	150	7.3%	30.8%	0.0903	1.0555	$2.18
NSW1	NSW NE Wind	NSWNEWind	1/01/2012		Wind	Wind	180.5	63.175	63.175	1.0%	100.0%	0.0000	0.0000	$1.75
NSW1	Redbank Power Station	REDBANK1	1/01/2009		Steam turbine	Black coal	150	75	135	8.0%	29.3%	0.0900	1.1058	$1.18
NSW1	Shoalhaven Bendeela Power Station	SHGEN	1/01/2012		Hydro	Hydro	240	0	30	1.0%	100.0%	0.0000	0.0000	$9.23
NSW1	Smithfield Energy Facility	SITHE01	1/01/2009		Cogeneration	Na ural gas	176	140	165	5.0%	41.0%	0.0513	0.4504	$2.37
NSW1	Tallawarra	Tallawarra1	1/07/2010		Gas turbine combined cycle	Na ural gas	410	205	320	3.0%	50.0%	0.0513	0.3694	$1.04
NSW1	Tumut 1 4x82.4MW NSW	UPPTUMUTNSW1	1/01/2009		Hydro	Hydro	616	0	220	1.0%	100.0%	0.0000	0.0000	$7.18
NSW1	Tumut 3 6x250MW NSW	TUMUT3NSW1	1/01/2009		Hydro	Hydro	1500	0	220	1.0%	100.0%	0.0000	0.0000	$11.28
NSW1	Unranquinty	Uran1	15/01/2009		Gas turbine	Na ural gas	166	0	10	3.0%	32.0%	0.0513	0.5771	$9.98
NSW1	Unranquinty	Uran2	15/01/2009		Gas turbine	Na ural gas	166	0	10	3.0%	32.0%	0.0513	0.5771	$9.98
NSW1	Unranquinty	Uran3	15/01/2009		Gas turbine	Na ural gas	166	0	10	3.0%	32.0%	0.0513	0.5771	$9.98
NSW1	Unranquinty	Uran4	15/01/2009		Gas turbine	Na ural gas	166	0	10	3.0%	32.0%	0.0513	0.5771	$9.98
NSW1	Vales Point B Power Station	VP5	1/01/2012		Steam turbine	Black coal	660	250	460	4.6%	35.4%	0.0898	0.9132	$1.18
NSW1	Vales Point B Power Station	VP6	1/01/2012		Steam turbine	Black coal	660	250	390	4.6%	35.4%	0.0898	0.9132	$1.18
NSW1	Wa lerawang C Power Station	WW7	1/01/2012		Steam turbine	Black coal	500	250	250	7.3%	33.1%	0.0874	0.9506	$1.31
NSW1	Wa lerawang C Power Station	WW8	1/01/2012		Steam turbine	Black coal	500	250	250	7.3%	33.1%	0.0874	0.9506	$1.31

Data source: ACIL Tasman

Table 29 Initial setting for existing and committed plant, Qld

Region	Generator	DUID	From Date	To Date	Gen Type	Fuel	Unit Size (MW)	Min Gen (MW)	Contract Cover (MW)	Aux (%)	Thermal efficiency (HHV sent-out, %)	Emission factor (t CO2/GJ)	Emission factor (t CO2/MWh)	Var O&M (2009 $/MWh, sent-out)
QLD1	Barcaldine Power Sta ion	BARCALDN	1/01/2009		Gas turbine	Natural gas	55	27	20	3.0%	40.0%	0.0513	0.4617	$2.37
QLD1	Barron Gorge	BARRON-1	1/01/2009		Hydro	Hydro	30	1	14	1.0%	100.0%	0.0000	0.0000	$11.28
QLD1	Barron Gorge	BARRON-2	1/01/2009		Hydro	Hydro	30	2	14	1.0%	100.0%	0.0000	0.0000	$11.28
QLD1	Braemar	BRAEMAR1	1/01/2010		Gas turbine	Natural gas	168	0	150	2.5%	30.0%	0.0513	0.6156	$7.83
QLD1	Braemar	BRAEMAR1	1/01/2010		Gas turbine	Natural gas	168	150	150	2.5%	30.0%	0.0513	0.6156	$7.83
QLD1	Braemar	BRAEMAR2	1/01/2010		Gas turbine	Natural gas	168	150	150	2.5%	30.0%	0.0513	0.6156	$7.83
QLD1	Braemar	BRAEMAR3	1/01/2010		Gas turbine	Natural gas	168	150	150	2.5%	30.0%	0.0513	0.6156	$7.83
QLD1	Braemar_Two	BRAEMAR5	1/07/2009		Gas turbine	Natural gas	153	150	150	2.5%	30.0%	0.0513	0.6156	$7.83
QLD1	Braemar_Two	BRAEMAR6	1/07/2009		Gas turbine	Natural gas	153	0	150	2.5%	30.0%	0.0513	0.6156	$7.83
QLD1	Braemar_Two	BRAEMAR7	1/07/2009		Gas turbine	Natural gas	153	0	0	2.5%	30.0%	0.0513	0.6156	$7.83
QLD1	Callide B Power Station	CALL_B_1	1/01/2009		Steam turbine	Black coal	350	220	250	7.0%	36.1%	0.0950	0.9474	$1.19
QLD1	Callide B Power Station	CALL_B_2	1/01/2009		Steam turbine	Black coal	350	220	220	7.0%	36.1%	0.0950	0.9474	$1.19
QLD1	Callide Power Plant	CPP_3	1/01/2012		Steam turbine	Black coal	450	200	325	4.8%	36.5%	0.0950	0.9370	$2.70
QLD1	Callide Power Plant	CPP_4	1/01/2012		Steam turbine	Black coal	450	200	325	4.8%	36.5%	0.0950	0.9370	$2.70
QLD1	Collinsv lle Power Station	COLNSV_1	1/01/2009		Steam turbine	Black coal	31	12	8	8.0%	27.7%	0.0894	1.1619	$1.31
QLD1	Collinsv lle Power Station	COLNSV_2	1/01/2009		Steam turbine	Black coal	31	0	0	8.0%	27.7%	0.0894	1.1619	$1.31
QLD1	Collinsv lle Power Station	COLNSV_3	1/01/2009		Steam turbine	Black coal	31	0	0	8.0%	27.7%	0.0894	1.1619	$1.31
QLD1	Collinsv lle Power Station	COLNSV_4	1/01/2009		Steam turbine	Black coal	31	0	0	8.0%	27.7%	0.0894	1.1619	$1.31
QLD1	Collinsv lle Power Station	COLNSV_5	1/01/2009		Steam turbine	Black coal	66	0	0	8.0%	27.7%	0.0894	1.1619	$1.31
QLD1	Condamine Power Station	CONDAMINE1	1/01/2012		Gas turbine combined cycle	Natural gas	140	135	90	3.0%	48.0%	0.0513	0.3848	$1.04
QLD1	Darling Downs ATR	DDATR1	1/04/2010		Gas turbine combined cycle	Natural gas	630	0	500	6.0%	46.0%	0.0513	0.4015	$1.04
QLD1	Gladstone	GSTONE1	1/01/2012		Steam turbine	Black coal	280	110	200	5.0%	35.2%	0.0921	0.9419	$1.18
QLD1	Gladstone	GSTONE2	1/01/2012		Steam turbine	Black coal	280	110	200	5.0%	35.2%	0.0921	0.9419	$1.18
QLD1	Gladstone	GSTONE3	1/01/2012		Steam turbine	Black coal	280	110	160	5.0%	35.2%	0.0921	0.9419	$1.18
QLD1	Gladstone	GSTONE4	1/01/2012		Steam turbine	Black coal	280	110	160	5.0%	35.2%	0.0921	0.9419	$1.18
QLD1	Gladstone	GSTONE5	1/01/2012		Steam turbine	Black coal	280	110	160	5.0%	35.2%	0.0921	0.9419	$1.18
QLD1	Gladstone	GSTONE6	1/01/2012		Steam turbine	Black coal	280	110	160	5.0%	35.2%	0.0921	0.9419	$1.18
QLD1	Kareeya	KAREEYA1	1/01/2009		Hydro	Hydro	21	8	10	1.0%	100.0%	0.0000	0.0000	$6.15
QLD1	Kareeya	KAREEYA2	1/01/2009		Hydro	Hydro	21	8	10	1.0%	100.0%	0.0000	0.0000	$6.15
QLD1	Kareeya	KAREEYA3	1/01/2009		Hydro	Hydro	18	8	10	1.0%	100.0%	0.0000	0.0000	$6.15
QLD1	Kareeya	KAREEYA4	1/01/2009		Hydro	Hydro	21	8	10	1.0%	100.0%	0.0000	0.0000	$6.15
QLD1	Kogan Creek	KPP_1	1/01/2011		Steam turbine	Black coal	750	350	572	8.0%	37.5%	0.0940	0.9024	$1.25
QLD1	Mackay Gas Turbine	MACKAYGT	1/01/2009		Gas turbine	Fuel o l	34	0	5	3.0%	28.0%	0.0697	0.8961	$8.94
QLD1	M llmerran Power Plant	MPP_1	1/01/2009		Steam turbine	Black coal	425.5	100	350	4.7%	36.9%	0.0920	0.8976	$2.81
QLD1	M llmerran Power Plant	MPP_2	1/01/2009		Steam turbine	Black coal	425.5	100	350	4.7%	36.9%	0.0920	0.8976	$2.81
QLD1	Mt Stuart Gas Turbine	MSTUART1	1/01/2009		Gas turbine	Liquid Fuel	146	0	30	3.0%	30.0%	0.0697	0.8364	$8.94
QLD1	Mt Stuart Gas Turbine	MSTUART2	1/01/2009		Gas turbine	Liquid Fuel	146	0	30	3.0%	30.0%	0.0697	0.8364	$8.94
QLD1	Mt Stuart Gas Turbine	MSTUART3	1/07/2009		Gas turbine	Liquid Fuel	126	0	30	3.0%	30.0%	0.0697	0.8364	$8.94
QLD1	Oakey Power Station	OAKEY1	1/01/2010		Gas turbine	Natural gas	141	40	5	3.0%	32.6%	0.0513	0.5665	$9.50
QLD1	Oakey Power Station	OAKEY2	1/01/2010		Gas turbine	Natural gas	141	40	5	3.0%	32.6%	0.0513	0.5665	$9.50
QLD1	Roma Gas Turbine Station	ROMA_7	1/01/2010		Gas turbine	Natural gas	40	38	32	3.0%	30.0%	0.0513	0.6156	$9.50
QLD1	Roma Gas Turbine Station	ROMA_8	1/01/2010		Gas turbine	Natural gas	40	38	32	3.0%	30.0%	0.0513	0.6156	$9.50
QLD1	Stanwell Power Station	STAN-1	1/01/2009		Steam turbine	Black coal	360	190	230	7.0%	36.4%	0.0904	0.8941	$3.18
QLD1	Stanwell Power Station	STAN-2	1/01/2009		Steam turbine	Black coal	360	190	230	7.0%	36.4%	0.0904	0.8941	$3.18
QLD1	Stanwell Power Station	STAN-3	1/01/2009		Steam turbine	Black coal	360	190	190	7.0%	36.4%	0.0904	0.8941	$3.18
QLD1	Stanwell Power Station	STAN-4	1/01/2009		Steam turbine	Black coal	360	190	230	7.0%	36.4%	0.0904	0.8941	$3.18
QLD1	Swanbank E Gas Turbine	SWAN_E	1/07/2010		Gas turbine combined cycle	Coal seam	385	150	180	3.0%	47.0%	0.0513	0.3929	$1.04
QLD1	Tarong North Power Station	TNPS1	1/01/2009		Steam turbine	Black coal	443	175	250	5.0%	39.2%	0.0921	0.8458	$1.42
QLD1	Tarong Power Station	TARONG#1	1/01/2010		Steam turbine	Black coal	350	140	240	8.0%	36.2%	0.0921	0.9159	$7.42
QLD1	Tarong Power Station	TARONG#2	1/10/2009		Steam turbine	Black coal	350	140	200	8.0%	36.2%	0.0921	0.9159	$7.42
QLD1	Tarong Power Station	TARONG#3	1/10/2009		Steam turbine	Black coal	350	140	200	8.0%	36.2%	0.0921	0.9159	$7.42
QLD1	Tarong Power Station	TARONG#4	1/10/2009		Steam turbine	Black coal	350	140	200	8.0%	36.2%	0.0921	0.9159	$7.42
QLD1	Townsville Power Station	YABULU	1/07/2010		Gas turbine combined cycle	Coal seam	240	113	113	3.0%	46.0%	0.0513	0.4015	$1.04
QLD1	Wivenhoe Power Station	W/HOE#1	1/01/2009		Hydro	Hydro	250	0	40	1.0%	100.0%	0.0000	0.0000	$0.00
QLD1	Wivenhoe Power Station	W/HOE#2	1/07/2009		Hydro	Hydro	250	0	20	1.0%	100.0%	0.0000	0.0000	$0.00
QLD1	Yarwun Cogen	YARWUN	1/01/2011		Gas turbine	Natural gas	168	143	143	2.0%	34.0%	0.0513	0.5432	$0.00

Data source: ACIL Tasman

Table 30 Initial setting for existing and committed plant, SA

Region	Generator	DUID	From Date	To Date	Gen Type	Fuel	Unit Size (MW)	Min Gen (MW)	Contract Cover (MW)	Aux (%)	Thermal efficiency (HHV sent-out, %)	Emission factor (t CO2/GJ)	Emission factor (t CO2/MWh)	Var O&M (2009 $/MWh, sent-out)
SA1	Angaston	ANGAS1	1/01/2009		Gas turbine	Distillate	30	0	0	2.5%	26.0%	0.0679	0.9402	$9.50
SA1	Dry Creek Gas Turbine Station	DRYCGT1	1/01/2009		Gas turbine	Natural gas	52	0	0	3.0%	26.0%	0.0513	0.7103	$9.50
SA1	Dry Creek Gas Turbine Station	DRYCGT2	1/01/2009		Gas turbine	Natural gas	52	0	0	3.0%	26.0%	0.0513	0.7103	$9.50
SA1	Dry Creek Gas Turbine Station	DRYCGT3	1/01/2009		Gas turbine	Natural gas	52	0	0	3.0%	26.0%	0.0513	0.7103	$9.50
SA1	Hallett Power Station	AGLHAL	1/01/2009		Gas turbine	Natural gas	180	0	10	2.5%	24.0%	0.0513	0.7695	$9.50
SA1	Ladbroke Grove Power Station	LADBROK1	1/01/2009		Gas turbine	Natural gas	40	0	35	3.0%	30.0%	0.0513	0.6156	$3.55
SA1	Ladbroke Grove Power Station	LADBROK2	1/01/2009		Gas turbine	Natural gas	40	0	35	3.0%	30.0%	0.0513	0.6156	$3.55
SA1	Mintaro Gas Turbine Station	MINTARO	1/01/2009		Gas turbine	Natural gas	90	0	0	3.0%	28.0%	0.0513	0.6596	$9.50
SA1	Northern Power Station	NPS1	1/07/2010		Steam turbine	Black coal	265	190	240	5.0%	34.9%	0.0910	0.9387	$1.18
SA1	Northern Power Station	NPS2	1/07/2010		Steam turbine	Black coal	265	190	240	5.0%	34.9%	0.0910	0.9387	$1.18
SA1	Osborne Power Station	OSB-AG	1/01/2009		Cogeneration	Natural gas	180	125	132	5.0%	42.0%	0.0513	0.4397	$5.03
SA1	Pelican Point Power Station	PPCCGT	1/07/2010		Gas turbine combined cycle	Natural gas	485	370	440	2.0%	48.0%	0.0513	0.3848	$1.04
SA1	Playford B Power Station	PLAYB-AG	1/01/2009		Steam turbine	Black coal	240	0	0	8.0%	21.9%	0.0910	1.4959	$2.97
SA1	Port Lincoln Gas Turbine	POR01	1/01/2009		Gas turbine	Distillate	50	0	50	8.0%	26.0%	0.0679	0.9402	$9.50
SA1	Quarantine Power Station	QPS1	1/01/2009		Gas turbine	Natural gas	24	0	10	5.0%	32.0%	0.0513	0.5771	$9.50
SA1	Quarantine Power Station	QPS2	1/01/2009		Gas turbine	Natural gas	24	0	10	5.0%	32.0%	0.0513	0.5771	$9.50
SA1	Quarantine Power Station	QPS3	1/01/2009		Gas turbine	Natural gas	24	0	10	5.0%	32.0%	0.0513	0.5771	$9.50
SA1	Quarantine Power Station	QPS4	1/01/2009		Gas turbine	Natural gas	24	0	10	5.0%	32.0%	0.0513	0.5771	$9.50
SA1	Quarantine Power Station	QPS5	1/01/2009		Gas turbine	Natural gas	120	0	60	5.0%	32.0%	0.0513	0.5771	$9.50
SA1	SA NE Wind	SANEWind1	1/01/2012		Wind	Wind	172	172	172	1.0%	100.0%	0.0000	0.0000	$1.75
SA1	Snuggery Power Station	SNUG1	1/01/2009		Gas turbine	Distillate	63	0	20	3.0%	26.0%	0.0679	0.9402	$9.50
SA1	Torrens Island Power Station A	TORRA1	1/01/2010		Steam turbine	Natural gas	120	2	2	5.0%	30.0%	0.0513	0.6156	$2.23
SA1	Torrens Island Power Station A	TORRA2	1/01/2010		Steam turbine	Natural gas	120	2	2	5.0%	30.0%	0.0513	0.6156	$2.23
SA1	Torrens Island Power Station A	TORRA3	1/01/2010		Steam turbine	Natural gas	120	2	2	5.0%	30.0%	0.0513	0.6156	$2.23
SA1	Torrens Island Power Station A	TORRA4	1/01/2010		Steam turbine	Natural gas	120	2	2	5.0%	30.0%	0.0513	0.6156	$2.23
SA1	Torrens Island Power Station B	TORRB1	1/01/2012		Steam turbine	Natural gas	200	40	110	5.0%	32.0%	0.0513	0.5771	$2.23
SA1	Torrens Island Power Station B	TORRB2	1/01/2012		Steam turbine	Natural gas	200	40	110	5.0%	32.0%	0.0513	0.5771	$2.23
SA1	Torrens Island Power Station B	TORRB3	1/01/2012		Steam turbine	Natural gas	200	40	110	5.0%	32.0%	0.0513	0.5771	$2.23
SA1	Torrens Island Power Station B	TORRB4	1/01/2012		Steam turbine	Natural gas	200	40	75	5.0%	32.0%	0.0513	0.5771	$2.23

Data source: ACIL Tasman

Table 31 Initial setting for existing and committed plant, Tas

Region	Generator	DUID	From Date	To Date	Gen Type	Fuel	Unit Size (MW)	Min Gen (MW)	Contract Cover (MW)	Aux (%)	Thermal efficiency (HHV sent-out, %)	Emission factor (t CO2/GJ)	Emission factor (t CO2/MWh)	Var O&M (2009 $/MWh, sent-out)
TAS1	Bastyan	BASTYAN1	1/01/2009		Hydro	Hydro	79.9	14	42	5.0%	100.0%	0.0000	0.0000	$6.15
TAS1	Bell Bay Three	BELLBAYTHREE1	1/07/2009		Gas turbine	Natural gas	60	0	30	2.5%	29.0%	0.0513	0.6368	$7.83
TAS1	Bell Bay Three	BELLBAYTHREE2	1/07/2009		Gas turbine	Natural gas	60	0	30	2.5%	29.0%	0.0513	0.6368	$7.83
TAS1	Bell Bay Three	BELLBAYTHREE3	1/07/2009		Gas turbine	Natural gas	60	0	30	2.5%	29.0%	0.0513	0.6368	$7.83
TAS1	Cethana	CETHANA1	1/01/2009		Hydro	Hydro	85	21	63	0.5%	100.0%	0.0000	0.0000	$6.15
TAS1	Devils Gate	DEVILS1	1/01/2009		Hydro	Hydro	60	32	60	0.5%	100.0%	0.0000	0.0000	$6.15
TAS1	Fisher	FISHER1	1/01/2009		Hydro	Hydro	43.2	10	30	0.5%	100.0%	0.0000	0.0000	$5.13
TAS1	Gordon	GORDON1	1/01/2012		Hydro	Hydro	432	0	125	0.5%	100.0%	0.0000	0.0000	$5.13
TAS1	John Butters	BUTTERS1	1/01/2009		Hydro	Hydro	144	0	50	0.5%	100.0%	0.0000	0.0000	$6.15
TAS1	Lake Echo	ECHO1	1/01/2009		Hydro	Hydro	32.4	0	0	0.5%	100.0%	0.0000	0.0000	$6.15
TAS1	Lemonthyme_Wilmot	LEMONTHYME1	1/01/2009		Hydro	Hydro	51	5	15	0.5%	100.0%	0.0000	0.0000	$6.15
TAS1	Lemonthyme_Wilmot	WILMOT1	1/01/2009		Hydro	Hydro	30.6	8	24	0.5%	100.0%	0.0000	0.0000	$6.15
TAS1	Liapootah_Wayatinah_Catagunya	CATAGUNYA1	1/01/2009		Hydro	Hydro	48	3	9	0.5%	100.0%	0.0000	0.0000	$6.15
TAS1	Liapootah_Wayatinah_Catagunya	LIAPOOTAH1	1/01/2009		Hydro	Hydro	83.7	14	42	0.5%	100.0%	0.0000	0.0000	$6.15
TAS1	Liapootah_Wayatinah_Catagunya	WAYATINAH1	1/01/2009		Hydro	Hydro	38.3	10	30	0.5%	100.0%	0.0000	0.0000	$6.15
TAS1	Mackintosh	MACKINTOSH1	1/01/2009		Hydro	Hydro	79.9	20	60	0.5%	100.0%	0.0000	0.0000	$6.15
TAS1	Meadowbank	MEADOWBANK1	1/01/2009		Hydro	Hydro	40	24	40	0.5%	100.0%	0.0000	0.0000	$6.15
TAS1	Poatina	POATINA1	1/01/2012		Hydro	Hydro	300	0	50	0.5%	100.0%	0.0000	0.0000	$6.15
TAS1	Reece	REECE1	1/01/2009		Hydro	Hydro	231.2	93	231.2	0.5%	100.0%	0.0000	0.0000	$6.15
TAS1	Tamar Valley Power Station CCGT1	TVPSCCGT1U1	1/01/2012		Gas turbine combined cycle	Natural gas	200	125	180	3.0%	48.0%	0.0513	0.3848	$1.05
TAS1	Tarraleah	TARRALEAH	1/01/2009		Hydro	Hydro	90	36	90	0.5%	100.0%	0.0000	0.0000	$6.15
TAS1	Trevallyn	TREVALLYN	1/01/2009		Hydro	Hydro	80	38	80	0.5%	100.0%	0.0000	0.0000	$6.15
TAS1	Tribute	TRIBUTE1	1/01/2009		Hydro	Hydro	82.8	20	60	0.5%	100.0%	0.0000	0.0000	$6.15
TAS1	Tungatinah	TUNGATINAH1	1/01/2009		Hydro	Hydro	125	20	60	0.5%	100.0%	0.0000	0.0000	$6.15

Data source: ACIL Tasman

Table 32 **Initial setting for existing and committed plant, Vic**

Region	Generator	DUID	From Date	To Date	Gen Type	Fuel	Unit Size (MW)	Min Gen (MW)	Contract Cover (MW)	Aux (%)	Thermal efficiency (HHV sent-out, %)	Emission factor (t CO2/GJ)	Emission factor (t CO2/MWh)	Var O&M (2009 $/MWh, sent-out)
VIC1	Anglesea Power Station	APS	1/01/2009		Steam turbine	Brown coal	160	150	160	10.0%	27.2%	0.0910	1.2044	$1.18
VIC1	Bairnsdale Power Station	BDL01	1/01/2009		Gas turbine	Natural gas	46	0	20	3.0%	34.0%	0.0513	0.5432	$2.23
VIC1	Bairnsdale Power Station	BDL02	1/01/2009		Gas turbine	Natural gas	46	10	20	3.0%	34.0%	0.0513	0.5432	$2.23
VIC1	Bogong	BOGONG1	1/10/2009		Hydro	Hydro	140	4	20	1.0%	100.0%	0.0000	0.0000	$7.18
VIC1	Dartmouth Power Station	DARTM1	1/01/2012		Hydro	Hydro	158	0	35	1.0%	100.0%	0.0000	0.0000	$6.15
VIC1	Eildon Power Station	EILDON1	1/01/2009		Hydro	Hydro	60	0	20	1.0%	100.0%	0.0000	0.0000	$9.23
VIC1	Eildon Power Station	EILDON2	1/10/2009		Hydro	Hydro	60	0	20	1.0%	100.0%	0.0000	0.0000	$9.23
VIC1	Energy Brix Complex	MOR1	1/01/2009		Steam turbine	Brown coal	90	50	55	15.0%	24.0%	0.0990	1.4850	$2.18
VIC1	Energy Brix Complex	MOR2	1/01/2009		Steam turbine	Brown coal	30	14	14	15.0%	24.0%	0.0990	1.4850	$2.18
VIC1	Energy Brix Complex	MOR3	1/01/2009		Steam turbine	Brown coal	75	37	37	15.0%	24.0%	0.0990	1.4850	$2.18
VIC1	Hazelwood Power Station	HWPS1	1/01/2012		Steam turbine	Brown coal	205	130	150	10.0%	22.0%	0.0930	1.5218	$1.18
VIC1	Hazelwood Power Station	HWPS2	1/01/2012		Steam turbine	Brown coal	205	130	150	10.0%	22.0%	0.0930	1.5218	$1.18
VIC1	Hazelwood Power Station	HWPS3	1/01/2012		Steam turbine	Brown coal	205	130	150	10.0%	22.0%	0.0930	1.5218	$1.18
VIC1	Hazelwood Power Station	HWPS4	1/01/2012		Steam turbine	Brown coal	205	130	150	10.0%	22.0%	0.0930	1.5218	$1.18
VIC1	Hazelwood Power Station	HWPS5	1/01/2012		Steam turbine	Brown coal	205	130	150	10.0%	22.0%	0.0930	1.5218	$1.18
VIC1	Hazelwood Power Station	HWPS6	1/01/2012		Steam turbine	Brown coal	205	130	150	10.0%	22.0%	0.0930	1.5218	$1.18
VIC1	Hazelwood Power Station	HWPS7	1/01/2012		Steam turbine	Brown coal	205	130	150	10.0%	22.0%	0.0930	1.5218	$1.18
VIC1	Hazelwood Power Station	HWPS8	1/01/2012		Steam turbine	Brown coal	205	130	180	10.0%	22.0%	0.0930	1.5218	$1.18
VIC1	Hume Power Station Vic	HUMEV	1/01/2009		Hydro	Hydro	29	12	0	1.0%	100.0%	0.0000	0.0000	$6.15
VIC1	Jeeralang A Power Sta ion	JLA01	1/01/2009		Gas turbine	Natural gas	57	0	20	3.0%	22.9%	0.0513	0.8065	$8.94
VIC1	Jeeralang A Power Sta ion	JLA02	1/01/2009		Gas turbine	Natural gas	57	0	20	3.0%	22.9%	0.0513	0.8065	$8.94
VIC1	Jeeralang A Power Sta ion	JLA03	1/01/2009		Gas turbine	Natural gas	57	0	20	3.0%	22.9%	0.0513	0.8065	$8.94
VIC1	Jeeralang A Power Sta ion	JLA04	1/01/2009		Gas turbine	Natural gas	57	0	20	3.0%	22.9%	0.0513	0.8065	$8.94
VIC1	Jeeralang B Power Sta ion	JLB01	1/01/2009		Gas turbine	Natural gas	85	0	40	3.0%	22.9%	0.0513	0.8065	$8.94
VIC1	Jeeralang B Power Sta ion	JLB02	1/01/2009		Gas turbine	Natural gas	85	0	40	3.0%	22.9%	0.0513	0.8065	$8.94
VIC1	Jeeralang B Power Sta ion	JLB03	1/01/2009		Gas turbine	Natural gas	85	0	40	3.0%	22.9%	0.0513	0.8065	$8.94
VIC1	Laverton North Power Sta ion	LAVNORTH	1/01/2009		Gas turbine	Natural gas	312	0	0	2.5%	30.4%	0.0513	0.6075	$7.83
VIC1	Loy Yang A Power Station	LYA1	1/01/2009		Steam turbine	Brown coal	560	400	450	9.0%	27.2%	0.0915	1.2110	$1.18
VIC1	Loy Yang A Power Station	LYA2	1/01/2009		Steam turbine	Brown coal	520	400	450	9.0%	27.2%	0.0915	1.2110	$1.18
VIC1	Loy Yang A Power Station	LYA3	1/01/2009		Steam turbine	Brown coal	560	400	485	9.0%	27.2%	0.0915	1.2110	$1.18
VIC1	Loy Yang A Power Station	LYA4	1/01/2009		Steam turbine	Brown coal	540	400	450	9.0%	27.2%	0.0915	1.2110	$1.18
VIC1	Loy Yang B Power Station	LOYYB1	1/01/2009		Steam turbine	Brown coal	525	200	450	7.5%	26.6%	0.0915	1.2383	$1.18
VIC1	Loy Yang B Power Station	LOYYB1	1/01/2009		Steam turbine	Brown coal	525	200	400	7.5%	26.6%	0.0915	1.2383	$1.18
VIC1	Loy Yang B Power Station	LOYYB2	1/01/2009		Steam turbine	Brown coal	525	200	450	7.5%	26.6%	0.0915	1.2383	$1.18
VIC1	Loy Yang B Power Station	LOYYB2	1/01/2009		Steam turbine	Brown coal	525	200	400	7.5%	26.6%	0.0915	1.2383	$1.18
VIC1	McKay Power Station	MCKAY1	1/01/2009		Hydro	Hydro	100	0	0	1.0%	100.0%	0.0000	0.0000	$7.18
VIC1	McKay Power Station	MCKAY2	1/10/2009		Hydro	Hydro	60	0	0	1.0%	100.0%	0.0000	0.0000	$7.18
VIC1	Mortlake OCGT	MORTLAKE_OCG	1/01/2011		Gas turbine	Natural gas	275	0	0	3.0%	32.0%	0.0513	0.5771	$8.22
VIC1	Mortlake OCGT	MORTLAKE_OCG	1/01/2011		Gas turbine	Natural gas	275	0	0	3.0%	32.0%	0.0513	0.5771	$8.22
VIC1	Murray 1 10x95MW Vic	MURRAYVIC1	1/01/2009		Hydro	Hydro	1500	0	440	1.0%	100.0%	0.0000	0.0000	$6.15
VIC1	Newport Power Sta ion	NPS	1/01/2012		Steam turbine	Natural gas	500	0	100	5.0%	33.3%	0.0513	0.5546	$2.23
VIC1	Somerton Power Station	AGLSOM	1/01/2009		Gas turbine	Natural gas	160	0	5	2.5%	24.0%	0.0513	0.7695	$9.50
VIC1	Valley Power Peaking Facility	VPGS1	1/01/2009		Gas turbine	Natural gas	50	0	5	3.0%	24.0%	0.0513	0.7695	$9.50
VIC1	Valley Power Peaking Facility	VPGS2	1/01/2009		Gas turbine	Natural gas	50	0	5	3.0%	24.0%	0.0513	0.7695	$9.50
VIC1	Valley Power Peaking Facility	VPGS3	1/01/2009		Gas turbine	Natural gas	50	0	5	3.0%	24.0%	0.0513	0.7695	$9.50
VIC1	Valley Power Peaking Facility	VPGS4	1/01/2009		Gas turbine	Natural gas	50	0	5	3.0%	24.0%	0.0513	0.7695	$9.50
VIC1	Valley Power Peaking Facility	VPGS5	1/01/2009		Gas turbine	Natural gas	50	0	5	3.0%	24.0%	0.0513	0.7695	$9.50
VIC1	Valley Power Peaking Facility	VPGS6	1/01/2009		Gas turbine	Natural gas	50	0	5	3.0%	24.0%	0.0513	0.7695	$9.50
VIC1	VIC NE Wind	VICNEWind	1/08/2011	30/09/2011	Wind	Wind	67.2	20.16	20.16	1.0%	100.0%	0.0000	0.0000	$1.75
VIC1	VIC NE Wind	VICNEWind	1/10/2011	28/02/2012	Wind	Wind	207.2	76.66	76.66	1.0%	100.0%	0.0000	0.0000	$1.75
VIC1	VIC NE Wind	VICNEWind	1/03/2012		Wind	Wind	347.2	128.46	128.46	1.0%	100.0%	0.0000	0.0000	$1.75
VIC1	West Kiewa Power Station	WKEWA1	1/01/2009		Hydro	Hydro	31	2	0	1.0%	100.0%	0.0000	0.0000	$7.18
VIC1	West Kiewa Power Station	WKEWA2	1/01/2009		Hydro	Hydro	31	2	8	1.0%	100.0%	0.0000	0.0000	$7.18
VIC1	Yallourn W Power Station	YWPS1	1/01/2009		Steam turbine	Brown coal	360	220	280	8.9%	23.5%	0.0925	1.4170	$1.18
VIC1	Yallourn W Power Station	YWPS2	1/01/2009		Steam turbine	Brown coal	360	220	280	8.9%	23.5%	0.0925	1.4170	$1.18
VIC1	Yallourn W Power Station	YWPS3	1/01/2009		Steam turbine	Brown coal	380	220	323	8.9%	23.5%	0.0925	1.4170	$1.18
VIC1	Yallourn W Power Station	YWPS4	1/01/2009		Steam turbine	Brown coal	380	220	280	8.9%	23.5%	0.0925	1.417	$1.18

Data source: ACIL Tasman

A.1.3 Near term supply changes assumed

Table 33 below outlines the committed or advanced withdrawals and additions of plant assumed to be common in each of the scenarios.

Table 33 **Near-term additions to and withdrawals from generation capacity, by region**

Portfolio	Generator	Type	Nameplate capacity (MW)	Date-on	Date-off
			Victoria		
AGL Energy	Bogong	Hydro	140	Oct 2009	
Origin Energy	Mortlake	OCGT	550	Jan 2011	
Oaklands Hill	NE	Wind	67.2	Aug 2011	
Macarthur	NE	Wind	140	Oct 2011	
Macarthur	NE	Wind	140	March 2012	
			New South Wales		
TRUenergy	Tallawarra	CCGT/Gas	410	Jul 2008	
Origin Energy	Uranquinty	GT/Gas	664	From Feb 2009	
Delta	Colongra	GT/Gas	664	Dec 2009	
Delta	Munmorah	Black Coal	-600		Jul 2014
Delta	Mt Piper U1-U2	Black coal	+90MW per unit	Assumed not to proceed	
Eraring	Eraring	Black coal	+60MW per unit	2010	
			South Australia		
Origin Energy	Quarantine	OCGT	+120	Dec 2008	
AGL Energy	Hallett wind farm	Wind	95	April 2008	
Infigen	Lake Bonney Stage 2	Wind	159	July 2008	
Trust Power	Snowtown	Wind	99	July 2008	
AGL Energy	Hallett 2 wind farm	Wind	71	Nov 2009	
Infigen	Lake Bonney Stage 3	Wind	39	2010	
Pacific Hydro	Clements Gap	Wind	57	2010	
AGL Energy	Hallet Stage 4	Wind	132	2011	
AGL Energy	Oaklands Hill	Wind	63	2011	
Roaring 40s	Waterloo	Wind	111	2011	
			Queensland		
Queensland Gas Co	Condamine	CCGT/Gas	80/140	Feb 2009 80MW OCGT, 140MW CCGT by Aug 2009	
ERM	Braemar 2	OCGT/Gas	460	July 2009	
CS Energy	Swanbank B	Black coal	-440		April 2012
Origin Energy	Darling Downs	CCGT	630	January 2010	
Origin Energy	Mt Stuart	OCGT	126	October 2009	
Rio Tinto	Yarwun	CCGT/Cogen	168	January 2011	
			Tasmania		
Alinta	Tamar Valley PS	CCGT/Gas	200 + 40 (OCGT)	Jul 2009	
Bell Bay Power	Bell Bay PS	Gas	-240		October 2009

Data source: AEMO ESOO and ACIL Tasman

A.1.4 Short run marginal costs of plant

The NEM is modelled on a nominal basis and we assume that variable operating and maintenance costs and fuel costs escalate over time, relative to an assumed CPI of 2.5%.

A.1.5 Fuel prices

Fuel costs are more complex, in that they escalate at different rates and, the escalation in some cases is not smooth – reflecting step changes in the demand/supply balance of gas as well as changes (expiry and renewal) in coal contracts.

Gas

There are two key factors that are likely to affect gas demand on the East Coast of Australia over coming years:

- Increased reliance on gas for power generation.
- Expansion of LNG production, including proposed development of an East Coast LNG industry based on CSG.

Our modelling for gas assumes four 4 million tonne per annum LNG facilities constructed in 2014 to 2018. This has a demand for gas feed of 440 PJ/a commencing in 2014 and increasing to 880 PJ/a in 2018.

Ramp-up gas associated with LNG production is a significant matter for the gas market over the next decade. We conclude that the ramp-up gas can be dealt with through a number of mitigating measures and we do not anticipate the ramp-up gas having a material influence on price.

Gas prices for base/intermediate load plant are determined either:

- on a cost plus basis for gas fired power stations sited on dedicated resources (e.g. Darling Downs and Condamine)
- from estimated contract prices where information is available
- from estimated market based nodal prices (GasMark Global projection) incorporating transportation costs when contracts expire or for new entrants sited remotely from gas fields
- Where existing power stations contracts expire over time, a blended average of existing contract and estimated market prices is used.

Peaking plant gas prices are set in the same way as the base/intermediate load except that a 50% premium is added to reflect the optional value and intermittent nature of the gas supply. While many peaking plants store distillate as an emergency reserve, we assume that in the normal course of business that this reserve is not used.

Coal

We determine coal fuel costs based on ACIL Tasman's internal projections. We consider the prices and duration of existing coal contracts. Upon expiry of existing contracts these plants are assumed to move to market-based rates. We assume that power stations are able to negotiate contracts at either a ROM cost plus rate (allowing a return on capital employed in the mine) or 80% of the export parity price of ROM whichever is the higher. For power stations that are not mine mouth, we include the efficient cost of transportation – conveyor, rail or road.

Queensland black coal

In Qld there are four types of coal supply arrangement:

- mine mouth - own mine: Tarong, Kogan Creek, Millmerran
- mine mouth - captive third party mine: Callide B, Callide Power, Collinsville
- transported from captive third party mine: Stanwell
- transported from third party mine: Gladstone, Swanbank B

Power stations in Queensland relying on their own mine mouth coal supply are least likely to be affected by the high export prices and it has been assumed that they will offer marginal fuel costs into the market which are currently less than A$1.00/GJ. However they will be affected by mining cost increases which have increased rapidly in recent years in response to strong demand and high oil and tyre prices.

Power stations with a mine mouth operation with a third party supplier are likely to be under pressure to accept prices more in line with export parity particularly with price reviews and contract renewal. However the arrangements for the larger Callide power stations have two decades to run and have limited if any price reopeners.

In 2004 Stanwell entered a 16 year arrangement with the Curragh mine which is not linked to export prices. We expect that Stanwell will be actively seeking advantageous alternative arrangements when these current arrangements expire.

Gladstone and Swanbank which rely on transported coal from third party mines are at greatest risk of pass through of export prices. However Gladstone has a long term arrangement with Rolleston to take lower quality coal. Swanbank is likely to continue on similar arrangements beyond the current three year contract with the New Acland mine near Oakey as alternative markets are limited by the export infrastructure in the Brisbane region; which is at capacity with no prospect of an increase in the medium term.

NSW black coal

In NSW all coal is supplied to the power stations by third party coal mines under a variety of contractual arrangements with varying terms, prices and transport arrangements. These contracts vary from relatively short term (1 to 2 years) to very long term (20 years or more). Generally these contracts were written before the surge in export coal prices from early 2004 and carry contract prices which are generally well below the export parity value being experienced in today's export market.

New tonnage however will need to be sourced in a setting of higher export coal prices. There are a number of strategies which local power stations will employ to keep prices of new tonnage lower than export parity price and these include:

- gaining access to undeveloped resources and employing a contract miner to produce the coal. (there are many unallocated resources available in NSW for this purpose)
- offering firm contracts to potential new developments in order to achieve discounted prices by lowering the market and infrastructure risks associated new developments
- entering into long term contractual arrangements with mines aimed at achieving cost related pricing
- offering to take non-exportable high ash coal, oxidised coal and washery rejects and middlings.

We expect these purchase strategies to result in reductions of around 20% on the export parity price of coal at most locations.

Victorian brown coal

Extensive deposits of brown coal occur in the tertiary sedimentary basins of Latrobe Valley coalfield which contains some of the thickest brown coal seams in the world. The coal is up to 330 m thick and is made up of 4 main seams, separated by thin sand and clay beds. The total brown coal resource in the Latrobe Valley is estimated to be 394,000 million tonnes, with an estimated useable brown coal reserve of 50,000 million tonnes.

Anglesea's brown coal reserves are estimated at around 120 million tonnes. Average coal thickness is 27 metres. The coal is a high quality brown coal, with a heat value of just over 15MJ/kg.

Mine mouth dedicated coalmines supply all the power stations. The coalmines are owned by the same entities that own the power stations with two exceptions. The exceptions are the Loy Yang B power station, where the mine, which is in close proximity to the power station, is owned and operated by Loy Yang Power, the owners and operators of the Loy Yang A power station and Energy Brix which is supplied by Morwell mine.

The marginal price of coal for the Victorian power stations is generally taken as the marginal or cash costs of mining the coal.

The marginal cost of coal is used to calculate the marginal costs for the Victorian Power stations operating in the NEM. In the cases where the coal mine is owned by the power station (Yallourn, Hazelwood and Loy Yang A) the short run marginal costs mainly consist of the additional electricity and royalty costs involved in mining the marginal tonne of coal. For Anglesea the marginal cost of coal is taken to be the cost of extraction using trucks and shovels. The marginal price of coal for the two stations that purchase coal from nearby mines (Loy Yang B and Energy Brix) is taken to be the estimated cost per unit of production.

South Australia black coal

The only currently producing coalfield in South Australia is near Leigh Creek based on low-grade sub-bituminous black coal. The mining operation involves drilling, blasting and removal of overburden and coal by shovels and trucks. After mining, the crushed coal is railed to the Port Augusta power stations. Due to the steeply dipping seams, it is likely that economic recovery of coal will be limited to between 70 and 100 Mt at depths of 150–200 m.

The Leigh Creek mine is about 250kms from the Northern power station. A long-term freight contract is in place with Pacific National. The delivered cost of coal is estimated at $1.62/GJ. The marginal cost of coal in South Australia is taken as the average cash costs of production and transport. The life of the Leigh Creek mine is constantly under review and will depend on the cost of mining and transport.

Table 34 **Assumed fuel costs (2011-12 $/GJ) by station by year**

Region	Generator	Fuel	2011-12
NSW1	Bayswater	Black coal	$1.33
NSW1	Colongra	Natural gas	$7.31
NSW1	Eraring Power Station 330kv	Black coal	$1.81
NSW1	Eraring Power Station 500kv	Black coal	$1.81
NSW1	Hunter Valley Gas Turbine	Fuel oil	$31.87
NSW1	Liddell	Black coal	$1.33
NSW1	Mt Piper Power Station	Black coal	$1.87
NSW1	Munmorah Power Station	Black coal	$1.83
NSW1	Redbank Power Station	Black coal	$1.07
NSW1	Smithfield Energy Facility	Natural gas	$4.44
NSW1	Tallawarra	Natural gas	$4.03
NSW1	Unranquinty	Natural gas	$6.69
NSW1	Vales Point B Power Station	Black coal	$1.83
NSW1	Wallerawang C Power Station	Black coal	$1.87
QLD1	Barcaldine Power Station	Natural gas	$7.03
QLD1	Braemar	Natural gas	$4.60
QLD1	Braemar_Two	Natural gas	$3.07
QLD1	Callide B Power Station	Black coal	$1.39
QLD1	Callide Power Plant	Black coal	$1.39
QLD1	Collinsville Power Station	Black coal	$2.22
QLD1	Condamine Power Station	Natural gas	$1.00
QLD1	Darling Downs ATR	Natural gas	$3.63
QLD1	Gladstone	Black coal	$1.65
QLD1	Kogan Creek	Black coal	$0.79
QLD1	Mackay Gas Turbine	Fuel oil	$31.87
QLD1	Millmerran Power Plant	Black coal	$0.90
QLD1	Mt Stuart Gas Turbine	Liquid Fuel	$31.87
QLD1	Oakey Power Station	Natural gas	$4.48
QLD1	Roma Gas Turbine Station	Natural gas	$4.60
QLD1	Stanwell Peaking Facility	Fuel oil	$31.87
QLD1	Stanwell Power Station	Black coal	$1.48
QLD1	Swanbank B Power Station	Black coal	$2.32
QLD1	Swanbank E Gas Turbine	Coal seam methane	$3.65
QLD1	Tarong North Power Station	Black coal	$1.06
QLD1	Tarong Power Station	Black coal	$1.06
QLD1	Townsville Power Station	Coal seam methane	$4.28
QLD1	Yarwun Cogen	Natural gas	$3.77
SA1	Angaston	Distillate	$31.87
SA1	Dry Creek Gas Turbine Station	Natural gas	$4.99
SA1	Hallett Power Station	Natural gas	$7.05
SA1	Ladbroke Grove Power Station	Natural gas	$5.38
SA1	Mintaro Gas Turbine Station	Natural gas	$7.05
SA1	Northern Power Station	Black coal	$1.62
SA1	Osborne Power Station	Natural gas	$4.37
SA1	Pelican Point Power Station	Natural gas	$4.21
SA1	Playford B Power Station	Black coal	$1.62
SA1	Port Lincoln Gas Turbine	Distillate	$31.87
SA1	Quarantine Power Station	Natural gas	$6.37
SA1	Snuggery Power Station	Distillate	$31.87
SA1	Torrens Island Power Station A	Natural gas	$4.27
SA1	Torrens Island Power Station B	Natural gas	$4.27
TAS1	Bell Bay	Natural gas	$5.88
TAS1	Bell Bay Three	Natural gas	$5.88
TAS1	Tamar Valley Power Station CCGT1	Natural gas	$5.88
VIC1	Anglesea Power Station	Brown coal	$0.42
VIC1	Bairnsdale Power Station	Natural gas	$4.56
VIC1	Energy Brix Complex	Brown coal	$0.63
VIC1	Hazelwood Power Station	Brown coal	$0.09
VIC1	Jeeralang A Power Station	Natural gas	$4.28
VIC1	Jeeralang B Power Station	Natural gas	$4.28
VIC1	Laverton North Power Station	Natural gas	$4.52
VIC1	Loy Yang A Power Station	Brown coal	$0.09
VIC1	Loy Yang B Power Station	Brown coal	$0.39
VIC1	Mortlake OCGT	Natural gas	$5.97
VIC1	Newport Power Station	Natural gas	$4.49
VIC1	Somerton Power Station	Natural gas	$4.53
VIC1	Valley Power Peaking Facility	Natural gas	$4.27
VIC1	Yallourn W Power Station	Brown coal	$0.10

Note: These values are applied to the HHV heat rates to give a fuel cost in $/MWh.

Data source: *ACIL Tasman*

A.1.6 Thermal efficiency

The thermal efficiencies of all plant are shown above. The thermal efficiency values tabulated are measured as sent-out. Even though the model settles the market on a 'as generated' basis it uses a 'sent-out' SRMC for the purpose of formulating the offer curves as well as calculating the portfolio net revenue in the optimisation routine. As part of the settlement process, NEMMCO pays the generators based on their dispatch measured at the regional reference node (RRN) – which is the sent-out dispatch corrected for the MLF.

A.1.7 Marginal loss factors

The marginal loss factors (MLFs) are taken directly from the latest NEMMCO report – "List of Regional Boundaries and Marginal Loss Factors for the 2010/11 Financial Year". The MLFs are used in the settlement routine to adjust the offers of the generators. The generators themselves do not make this alteration to their offer curves – hence the short run marginal costs tabulated in the following section have not been adjusted for MLF.

A.1.8 Short run marginal costs

Taken together, the fuel costs, thermal efficiency and variable O&M costs determine the short run marginal cost (SRMC) for each station. Table 35 summarises the nominal SRMC assumed for each station.

Table 35 **Station SRMC (2011-12 $/MWh) for existing or committed plant**

Region	Generator	Fuel	2011-12
NSW1	Bayswater	Black coal	$14.15
NSW1	Colongra	Natural gas	$90.86
NSW1	Eraring Power Station 330kv	Black coal	$19.47
NSW1	Eraring Power Station 500kv	Black coal	$19.47
NSW1	Hunter Valley Gas Turbine	Fuel oil	$414.47
NSW1	Liddell	Black coal	$14.96
NSW1	Mt Piper Power Station	Black coal	$19.43
NSW1	Munmorah Power Station	Black coal	$23.42
NSW1	Redbank Power Station	Black coal	$14.18
NSW1	Smithfield Energy Facility	Natural gas	$40.93
NSW1	Tallawarra	Natural gas	$27.78
NSW1	Unranquinty	Natural gas	$83.71
NSW1	Vales Point B Power Station	Black coal	$19.64
NSW1	Wallerawang C Power Station	Black coal	$21.56
QLD1	Barcaldine Power Station	Natural gas	$59.42
QLD1	Braemar	Natural gas	$58.17
QLD1	Braemar_Two	Natural gas	$37.45
QLD1	Callide B Power Station	Black coal	$14.97
QLD1	Callide Power Plant	Black coal	$16.37
QLD1	Collinsville Power Station	Black coal	$29.88
QLD1	Condamine Power Station	Natural gas	$2.62
QLD1	Darling Downs ATR	Natural gas	$23.46
QLD1	Gladstone	Black coal	$17.94
QLD1	Kogan Creek	Black coal	$8.81
QLD1	Mackay Gas Turbine	Fuel oil	$413 90
QLD1	Millmerran Power Plant	Black coal	$11.55
QLD1	Mt Stuart Gas Turbine	Liquid Fuel	$386 92
QLD1	Oakey Power Station	Natural gas	$52.97
QLD1	Roma Gas Turbine Station	Natural gas	$59.92
QLD1	Stanwell Peaking Facility	Fuel oil	$0.00
QLD1	Stanwell Power Station	Black coal	$17.71
QLD1	Swanbank B Power Station	Black coal	$28.30
QLD1	Swanbank E Gas Turbine	Coal seam methane	$22.67
QLD1	Tarong North Power Station	Black coal	$10.77
QLD1	Tarong Power Station	Black coal	$18.06
QLD1	Townsville Power Station	Coal seam methane	$28.35
QLD1	Yarwun Cogen	Natural gas	$32.39
SA1	Angaston	Distillate	$445.61
SA1	Dry Creek Gas Turbine Station	Natural gas	$78.02
SA1	Hallett Power Station	Natural gas	$113 90
SA1	Ladbroke Grove Power Station	Natural gas	$67.23
SA1	Mintaro Gas Turbine Station	Natural gas	$99.02
SA1	Northern Power Station	Black coal	$17.70
SA1	Osborne Power Station	Natural gas	$42.23
SA1	Pelican Point Power Station	Natural gas	$32.26
SA1	Playford B Power Station	Black coal	$29.32
SA1	Port Lincoln Gas Turbine	Distillate	$445.61
SA1	Quarantine Power Station	Natural gas	$79.65
SA1	Snuggery Power Station	Distillate	$445.61
SA1	Torrens Island Power Station A	Natural gas	$34.58
SA1	Torrens Island Power Station B	Natural gas	$34.58
TAS1	Bell Bay	Natural gas	$0.00
TAS1	Bell Bay Three	Natural gas	$79.03
TAS1	Tamar Valley Power Station CCGT1	Natural gas	$42.44
VIC1	Anglesea Power Station	Brown coal	$6.64
VIC1	Bairnsdale Power Station	Natural gas	$49.95
VIC1	Energy Brix Complex	Brown coal	$11.56
VIC1	Hazelwood Power Station	Brown coal	$2.63
VIC1	Jeeralang A Power Station	Natural gas	$73.12
VIC1	Jeeralang B Power Station	Natural gas	$73.12
VIC1	Laverton North Power Station	Natural gas	$57.93
VIC1	Loy Yang A Power Station	Brown coal	$2 36
VIC1	Loy Yang B Power Station	Brown coal	$6.43
VIC1	Mortlake OCGT	Natural gas	$73.31
VIC1	Newport Power Station	Natural gas	$48.54
VIC1	Somerton Power Station	Natural gas	$74.49
VIC1	Valley Power Peaking Facility	Natural gas	$70.66
VIC1	Yallourn W Power Station	Brown coal	$2.73

Note: The SRMCs reported are as at 1 January for the given year. An SRMC of zero indicates the station is not available. The SRMCs for CCGTs in Queensland are reduced by an assumed GEC price; the SRMCs for CCGTs in other regions are reduced by an assumed NGAC price.

Data source: *ACIL Tasman generator database*

A.2 Offer strategies

Generation portfolios enter into electricity derivative contracts to hedge pool revenues in order to reduce earnings risk and avoid insolvency. In entering into these contracts generators are indifferent to RRP movements across the volume of these contracts except where RRP fall below the SRMC. Hence a short term optimal strategy is to offer all generation that is contracted at SRMC. However if all generators contract heavily and then offer all generation that is contracted at a price of SRMC, the RRP will tend to spiral downwards and future contracts will tend to reflect lower RRP expectations. Hence long term optimal strategies require some generation to be bid above SRMC to maintain underlying RRPs and by implication contract prices.

PowerMark provides a range of options with regard to the offer strategy used by each portfolio. Offer strategies include:

- Maximising dispatch, so that each portfolio attempts to maximise its output in each period – typically for price takers
- Maximising net uncontracted revenue – for price makers.

Net pool revenue is dispatch weighted pool revenue in each period less fuel costs. Only uncontracted revenue is maximised as the portfolio is assumed to be indifferent in the short term to the price it receives from the pool for that volume of its dispatch, which is contracted. It will only attempt to maximise its revenue for that proportion of its output, which is not under contract.

In order to avoid the downward price spiral noted above, the contract volume setting in PowerMark is not designed to fit exactly with actual contract volumes. Rather it is a setting that allows accurate simulation of the way in which portfolio generators bid in the market – i.e. large portions of volume at SRMC to guarantee a minimum volume with smaller portions of volume at multiples of SRMC to reflect the total cost of supply.

In the scenarios, for the most part, we have assumed the second optimising strategy (as we do in nearly all runs of PowerMark) that each portfolio will offer energy in order to attempt to maximise the returns from uncontracted revenue, reflecting an objective of maximising the returns from contracted and uncontracted revenues over the long term.

A.2.1 Hydro plant

Hydro plant have very low SRMCs so if PowerMark were to 'start' their bid curves at their true SRMC, in a manner similar to a thermal plant, then they would over the course of a year generate well beyond their energy constraints. Instead the model uses the notion of an opportunity cost for the water which attempts to maximise the net revenue of the plant but not break the energy constraint.

PowerMark allows the hydro plant to offer their capacity strategically – that is, they attempt to optimise their net pool revenue but at the same time satisfying their energy (water availability and storage) constraints. As a consequence, the offer curves may vary by season, day of week and time-of-day to reflect the energy constraints and profit maximising behaviour. Rather than using their true SRMC as a starting point, the hydro plant are assigned an opportunity cost which will change year on year depending on the demand/supply balance in the market.

We assume an annual energy constraint equal to the long term annual generation of the plant (which is equal to the long term average inflows).

A.2.2 Wind and geothermal plant

Wind and geothermal plant are assumed to offer their available capacity at a zero price to maximise the chance of dispatch.

In general, wind plants are assumed to achieve a capacity factor of 30%.

Geothermal plant will be assumed to achieve an 85% capacity factor. The implicit assumption here is that additional wells are drilled to offset the natural decline in performance of the existing wells, so that the capacity factor remains reasonably constant throughout the projection.

A.2.3 Offer curve construction

Regardless of offer strategy, for each plant, ACIL Tasman sets the first two tranches of the offer curve according to:

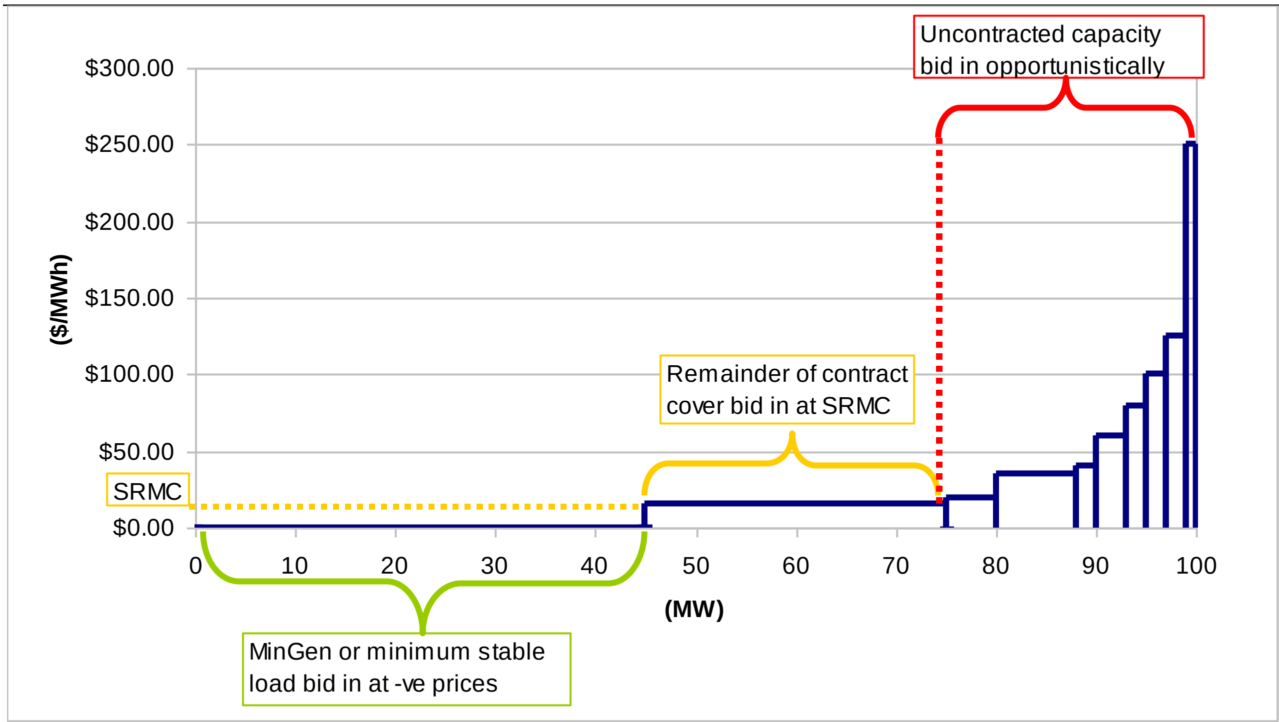
- the assumed level of MinGen, which is offered between -$1000/MWh and $0/MWh; and
- the assumed level of contract cover, which is offered at the SRMC of the plant.

In addition to the MinGen and contract cover settings; for some plant, tranches of the offer curve may be fixed to account for assumed cap contracts. This setting is mainly used for peaking plant and typically set to rounded dollar values between $100/MWh and $250/MWh.

A number of assumptions are made when setting the fixed part of the offer curve for each station. ACIL Tasman invests a great deal of time collating analysis of historical offer curves and separate market intelligence to formulate what it considers to be reasonable long term assumptions about the MinGen, contract cover and cap contract settings for each generator.

Finally, the projection assumes that the cap on price offers (or VoLL) is set at AUD10,000/MWh and rises to $12,500/MWh in July 2010. The offer curves of all plant are capped at this value. Although VoLL may be revised further, we assume that it does not otherwise change throughout the projection period.

Figure 12 **Example offer curve of a generator**



Data source: ACIL Tasman

A.3 Contract cover

Contract cover measures the extent to which generators have their RRP exposure covered by financial swap contracts (two-way hedges)[15]. In modelling pool markets, the level of swap contract cover is a key factor in price and dispatch outcomes. Based solely on short-run analysis, a generator would typically offer contracted capacity at marginal cost (save for below marginal cost bids in respect of 'MinGen' and ramp-up needs[16]), and will bid to maximise net revenues from the remaining uncontracted capacity.

However, this short run optimal strategy is not optimal in the long run as it drives RRPs down well below contract prices leading to lower contract prices in the future with an ongoing spiral downwards of pool and contract prices. Hence in practice at least some generators (generally the bigger portfolios with the most to gain and lose) are willing to sacrifice some contract revenue to avoid this downward spiral.

While swap contract levels are not publicly known, portfolio bid stacks do allow the level of capacity bid at marginal cost to be inferred. While this probably underestimates the total volume of contracts in place, it reflects the volume of contracts that each generator is willing to protect rather than sacrifice in the interests of long run profitability.

Within PowerMark, specification of swap contract levels means specification of the amount of capacity to be offered at or below marginal cost. It is estimated by reference to recent market experience and adjusted over time on the basis of an analysis of contracting incentives.

ACIL Tasman's analysis to date indicates that the lowest of the off-peak hours are heavily contracted as a proportion of load, whereas caps and other more exotic options are added to swaps in the peak periods to provide cost effective risk management.

ACIL Tasman establishes proxy values of swap contract cover for recent historical periods by 'reverse engineering' the swap contract cover and swap contract target assumptions such that they replicate actual power station dispatch and RRPs when actual demand data and outage data are substituted

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15 Caps impact on generator offering behaviour only to the extent that they relate to plant capacity that would normally be off-line.

16 'MinGen' (for minimum generation) is the estimated minimum level at which a plant can be technically and economically operated (for flame control and damage limitation). Generators usually offer this level of capacity at near zero or substantially negative prices in order to avoid being offloaded by the central dispatcher. It is rare — but does occur — for the RRP to settle at a negative "offload" price. Generators also tend to offer capacity at below marginal cost for periods when they are intent on 'ramping-up' in order to have the ability to offer greater amounts of capacity in a subsequent period, when RRPs are expected to be higher.

for projected demand and outages. The estimates derived in that way are plausible numbers in the opinion of market participants familiar with them. **We expect the level of contract cover in the market to stabilise, on a long term basis, at about 85-90% of all demand. Based on our modelling, this allows new entrants a reasonable level of contract cover as well as maintaining the contract levels of existing baseload plant.**

It is important to note that the levels of contract cover in the market assumed in the scenarios are expressed in terms of load, not in capacity.

A.4 Plant availability

A.4.1 Introduction

PowerMark includes in it for each generator a planned maintenance schedule and a set of random unplanned outages.

In 2005, ACIL Taman undertook an availability analysis of coal fired plant in the NEM spanning 1999 to 2004 using published NEMMCO data. The availability analysis grouped planned maintenance and forced outages together.

The analysis found that in Queensland the average outage days per year across all coal plant was 41 and the median was 37 – this equates to an availability of 88% and 90% respectively. The median was reported in an attempt to remove anomalous outages – such as the well recognised difficulties experienced by Millmerran – although it gave only a slightly lower result than the average.

The 75th percentile of the outage distribution was 60 days, which equates to 84% availability.

ACIL Tasman proposes to use an availability of 90% for coal plant.

There is not as much long term data available on CCGT plant in Queensland, but ACIL Tasman in its market modelling of the NEM and Singapore routinely assumes CCGTs experience 15 days per year of planned maintenance (which equates to 4%) and a 3% forced outage rate. **Therefore, ACIL Tasman uses an availability of 92% for CCGT plant**.

We assume a 1.5% forced outage rate for peaking plant. Although peaking plant undergo planned maintenance, we assume that this maintenance is scheduled during the off-peak months when the plant are rarely used. Given these plants typically have annual capacity factors of less than 5%, it appears reasonable to assume that their planned maintenance can be scheduled during periods when there is a very low probability of high priced outcomes in the NEM.

Therefore, ACIL Tasman proposes to use an availability of 98.5% for OCGT plant.

Hydro plants are assumed to have an overall availability of 95% per year.

Geothermal plants are assumed to have an overall availability of 90% per year.

A.4.2 Forced outage rates

Table 36 summarises the assumed annual forced outage rate by station.

A.4.3 Planned maintenance

Water-cooled black coal plant are generally assumed to have planned maintenance schedules that equate to about one month every two years.

Air-cooled black coal plant tend to have a schedule that equates to one month every year

The newer brown coal plant tend to have a schedule that equates to one month every four years and the older brown coal plant a schedule that equates to one month every year.

New entrant CCGTs and coal plant are assumed to be off-line one month every four years for planned maintenance.

Table 36 **Annual forced outage rate, by station**

Region	Generator	Fuel	UPO
NSW1	Bayswater	Black coal	3.0%
NSW1	Colongra	Natural gas	1.5%
NSW1	Eraring Power Station 330kv	Black coal	3.0%
NSW1	Eraring Power Station 500kv	Black coal	3.0%
NSW1	Hunter Valley Gas Turbine	Fuel oil	2.5%
NSW1	Liddell	Black coal	3.0%
NSW1	Mt Piper Power Station	Black coal	3.0%
NSW1	Munmorah Power Station	Black coal	7.0%
NSW1	Redbank Power Station	Black coal	4.0%
NSW1	Smithfield Energy Facility	Natural gas	2.5%
NSW1	Tallawarra	Natural gas	3.0%
NSW1	Unranquinty	Natural gas	1.5%
NSW1	Vales Point B Power Station	Black coal	3.0%
NSW1	Wallerawang C Power Station	Black coal	3.0%
QLD1	Barcaldine Power Station	Natural gas	2.5%
QLD1	Braemar	Natural gas	1.5%
QLD1	Braemar_Two	Natural gas	1.5%
QLD1	Callide B Power Station	Black coal	4.0%
QLD1	Callide Power Plant	Black coal	6.0%
QLD1	Collinsville Power Station	Black coal	4.0%
QLD1	Condamine Power Station	Natural gas	1.5%
QLD1	Darling Downs ATR	Natural gas	3.0%
QLD1	Gladstone	Black coal	4.0%
QLD1	Kogan Creek	Black coal	4.0%
QLD1	Mackay Gas Turbine	Fuel oil	1.5%
QLD1	Millmerran Power Plant	Black coal	5.0%
QLD1	Mt Stuart Gas Turbine	Liquid Fuel	2.5%
QLD1	Oakey Power Station	Natural gas	2.0%
QLD1	Roma Gas Turbine Station	Natural gas	3.0%
QLD1	Stanwell Power Station	Black coal	2.5%
QLD1	Swanbank B Power Station	Black coal	7.0%
QLD1	Swanbank E Gas Turbine	Coal seam methane	3.0%
QLD1	Tarong North Power Station	Black coal	3.0%
QLD1	Tarong Power Station	Black coal	3.0%
QLD1	Townsville Power Station	Coal seam methane	3.0%
QLD1	Yarwun Cogen	Natural gas	3.0%
SA1	Angaston	Distillate	1.5%
SA1	Dry Creek Gas Turbine Station	Natural gas	3.0%
SA1	Hallett Power Station	Natural gas	1.5%
SA1	Ladbroke Grove Power Station	Natural gas	3.0%
SA1	Mintaro Gas Turbine Station	Natural gas	1.5%
SA1	Northern Power Station	Black coal	5.0%
SA1	Osborne Power Station	Natural gas	3.0%
SA1	Pelican Point Power Station	Natural gas	3.0%
SA1	Playford B Power Station	Black coal	10.0%
SA1	Port Lincoln Gas Turbine	Distillate	1.5%
SA1	Quarantine Power Station	Natural gas	2.5%
SA1	Snuggery Power Station	Distillate	2.0%
SA1	Torrens Island Power Station A	Natural gas	4.5%
SA1	Torrens Island Power Station B	Natural gas	4.5%
TAS1	Bell Bay	Natural gas	3.0%
TAS1	Bell Bay Three	Natural gas	3.0%
TAS1	Tamar Valley Power Station CCGT1	Natural gas	3.0%
VIC1	Anglesea Power Station	Brown coal	3.0%
VIC1	Bairnsdale Power Station	Natural gas	2.5%
VIC1	Energy Brix Complex	Brown coal	2.5%
VIC1	Hazelwood Power Station	Brown coal	3.5%
VIC1	Jeeralang A Power Station	Natural gas	2.5%
VIC1	Jeeralang B Power Station	Natural gas	2.5%
VIC1	Laverton North Power Station	Natural gas	1.5%
VIC1	Loy Yang A Power Station	Brown coal	3.0%
VIC1	Loy Yang B Power Station	Brown coal	4.0%
VIC1	Mortlake OCGT	Natural gas	1.5%
VIC1	Newport Power Station	Natural gas	2.0%
VIC1	Somerton Power Station	Natural gas	1.5%
VIC1	Valley Power Peaking Facility	Natural gas	1.5%
VIC1	Yallourn W Power Station	Brown coal	4.0%

Data source: ACIL Tasman assumptions