Calculation of energy costs for the 2010-11BRCI Final Decision

Includes the calculation of
energy purchase costs, LRMC,
and other energy costs

Prepared for the Queensland Competition Authority

Final report of 14 May 2010

ACIL Tasman

Economics Policy Strategy

Reliance and Disclaimer

In conducting the analysis in this report ACIL Tasman has endeavoured to use what it considers is the best information available at the date of publication, including information supplied by the addressee. Unless stated otherwise, ACIL Tasman does not warrant the accuracy of any forecast or prediction in the report. Although ACIL Tasman exercises reasonable care when making forecasts or predictions, factors in the process, such as future market behaviour, are inherently uncertain and cannot be forecast or predicted reliably.

ACIL Tasman Pty Ltd

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

Melbourne (Head Office)
Level 6, 224-236 Queen Street
Melbourne VIC 3000

Telephone (+61 3) 9604 4400
Facsimile(+61 3) 9600 3155
Email melbourne@aciltasman.com.au

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

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

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

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

Darwin
Suite G1, Paspalis Centrepoint
48-50 Smith Street
Darwin NT 0800
GPO Box 908
Darwin NT 0801

Telephone(+61 8) 8943 0643
Facsimile(+61 8) 8941 0848
Emaildarwin@aciltasman.com.au

Perth
Centa Building C2, 118 Railway Street
West Perth WA 6005

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

Sydney
PO Box 1554
Double Bay NSW 1360

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

For information on this report

Please contact:

Paul Breslin or Marc Randell
Telephone (07) 3009 8700 or (07) 3009 8709
Mobile 0404 822 318 or 0404 822 319
Email p.breslin@aciltasman.com.au or m.randell@aciltasman.com.au

Contributing team members:

Marc Randell
Richard Lenton
Cara Stuetz

Contents

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 2010-11. 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 2010-11 year.
- Other energy costs that apply to electricity generators and retailers in Queensland, comprising;
  - Retailer costs associated with complying with the Commonwealth government's Renewable Energy Target (RET) scheme,
  - 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 in that part of this report which describes the calculation of each component.

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 Regulations 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.

ACIL Tasman's approach has been to consider the methodology used by CRA International (CRA) in calculating the BRCI for 2009-10 and described in their report (the CRA Report);

> Calculation of the Benchmark Retail Cost Index 2009-10, Final Report, dated 8 June 2009.

In general ACIL Tasman has adopted the methodology described by CRA so as to maintain as much consistency as possible between the two calculations. Differences arise in the models used (the least cost supply model for calculating LRMC and the market simulation models for projecting year ahead RRPs) but we have attempted to keep these differences to a minimum by using a similar greenfields approach to the LRMC calculation, a similar time period over which the calculation is made, the same approach to a contracting strategy and similar methodologies for forecasting load for the subject year.

In the case of data sources and forecasts, ACIL Tasman has generally used the CRA sources as a starting point and considered whether there have been any updates or revisions to the data that warrant a new source. The main source of data for the 2009-10 calculation was the report by Concept Economics[1] which relied on data prepared before October 2008. In order to use the latest available data, the LRMC calculation has relied on the more recent ACIL Tasman report[2] prepared for AEMO in April 2009. Even in using this report we have applied additional analysis in order to update some of the data or projections. For example coal prices into power stations are influenced to a certain degree by A$ export coal prices, which have changed recently with the appreciation of the Australian dollar.

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; costs arising from compliance with the Renewable Energy target and the Queensland Gas Electricity Scheme, market fees paid to AEMO and ancillary service costs.

---

[1] Concept Economics, "Review of Inputs to Cost Modelling of the NEM", dated 14 May 2009.

[2] ACIL Tasman, "Fuel resource, new entry and generation costs in the NEM", April 2009.

1.1 Summary of results

Table 1 below shows a summary of the cost of energy components of the 2010-11 BRCI Draft and Final Decisions. 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.

Table 1 **Summary of results for the energy cost components - 2010-11 BRCI for Draft and Final Decisions**

	Draft Decision 2010-11	Final Decision 2010-11	% Change
NEM load (MWh)	37,483,145	37,832,394	0.9%
Energy costs ($/MWh)			
LRMC	$58.51	$58.59	0.1%
Energy purchase costs (EPC)	$58.72	$58.51	-0.4%
Energy - based on 50% weighting	$58.62	$58.66	0.1%
Renewable Energy Target	$3.02	$3.05	1.0%
Queensland Gas Scheme	$2.80	$2.84	1.4%
NEM fees	$0.37	$0.34	-8.1%
Ancillary services	$0.45	$0.39	-13.3%
Total energy costs ($MWh)	$65.26	**$65.17**	-0.1%
Total energy costs ($ millions)	$2,446	$2,466	0.8%

2 The calculation of LRMC

2.1 Introduction

The Electricity Regulation 2006, section 106, states the following with respect to the calculation of 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 106(a) above. The model produces results consistent with 106(b) and (c) and we believe the approach, while taking into account the effects of schemes such as RECs and GECs on energy costs, does not double count the effects of these schemes.

In developing the LRMC component of the 2010-11 BRCI ACIL Tasman has taken the following steps.

- Developed recent and reliable forecasts of fuel, capital and O & M costs for the range of power stations in use in the NEM,
- Taken into account state and Commonwealth programs that add or subtract to energy costs, such as the RET and GEC schemes,
- Used these inputs in a least cost supply model which minimizes both short run and long run marginal costs in meeting future market demand.

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

The LRMC assumptions are the same for both Draft and Final Decisions except for the base load traces and some of the WACC assumptions. The Final decision is based on the actual NEM regional load traces for the whole of 2009 whereas the draft decision was based on the year to 30 September 2009. The risk free rate and debt basis point premium used in the calculation of the WACC have been adjusted to reflect recent developments.

2.2 PowerMark LT

PowerMark LT is a long term planning and analysis tool. It is a dynamic least cost model, which optimises existing and new generation operation and new investments over the selected period; given assumptions concerning demand growth, plant costs, interconnectors, 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.

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&M0. 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 operating and maintenance 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.

2.3 Forecasts of capital, fuel and O & M costs

2.3.1 Capital costs

The capital cost projections presented here have been sourced from the document prepared by ACIL Tasman for the Inter regional Planning Committee of the (then) NEMMCO in April 2009

> ACIL Tasman, "Fuel resource, new entry and generation costs in the NEM". April 2009

The capital cost forecasts have been checked to ensure the underlying assumptions are still relevant. The estimates reflect a long-run equilibrium level around which shorter-term perturbations may occur.

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 costs relating to IDC are implicitly included within the new entrant model, as discussed above.

An international database of published capital costs for new entrant power plant has also been used to provide an informed view of capital costs for new plant in the NEM.

For the emerging technologies published research reports, which include estimates of capital costs as well as projections in the capital costs to account for the learning curve effect, have been relied upon.

Table 2 details a selection of key background assumptions that were used for this exercise and Table 3 shows the capital cost projections for the range of technologies considered. The capital costs shown in Table 3 are sourced from ACIL Tasman's April 2009 report to the IRPC of NEMMCO. We believe they represent the most recent view of capital costs and include the impact of the global financial crisis and the recovery during 2009 on construction costs and the demand for new generation capacity.

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 report for years 2010-11 and 2011-12 (p6)
Exchange rate (USD/AUD)	0.75	Long-term assumption
International oil price (US$/bbl)	$80	ACIL Tasman assumption which aligns with EIA International Energy Outlook 2008 forecast on average over the period to 2020 (real 2008 dollars)
Internationally traded thermal coal price (A$/tonne)	$80	ACIL Tasman projection (in nominal dollars) for FOB Newcastle. Implies FOB price declining in real terms
LNG export facilities developed in Queensland	Total of 8 Mtpa capacity	Assumed two proposals reach FID: 4 Mtpa operational by 2014; further 4 Mtpa by 2018
Upstream gas developments	ACIL Tasman assumptions	Assumptions relating to level of CSG development and conventional exploration success
Discount rate for new entrants	6.81%	Post-tax real WACC

Table 3 **Capital costs ($/kW, 2010-11 $)**

	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19
ACIL Tasman April 2009										
Black Coal	$2,348	$2,268	$2,228	$2,190	$2,176	$2,163	$2,160	$2,157	$2,153	$2,149
Brown Coal	$2,583	$2,495	$2,451	$2,409	$2,394	$2,379	$2,376	$2,372	$2,368	$2,364
CCGT	$1,403	$1,307	$1,305	$1,282	$1,266	$1,263	$1,260	$1,256	$1,251	$1,247
OCGT	$1,010	$941	$939	$922	$911	$908	$905	$902	$898	$895
Wind	$2,588	$2,406	$2,356	$2,278	$2,275	$2,268	$2,260	$2,249	$2,236	$2,222
Hydro	$2,773	$2,773	$2,773	$2,773	$2,773	$2,773	$2,773	$2,773	$2,773	$2,773
Geothermal	$5,464	$5,504	$5,433	$5,363	$5,294	$5,226	$5,159	$5,093	$5,028	$4,963
Biomass	$5,131	$5,117	$5,097	$5,077	$5,057	$5,037	$5,017	$4,998	$4,977	$4,959

2.3.2 Operation and maintenance costs

Operating and maintenance (O&M) costs comprise of both fixed and variable components. Variable O&M (or VOM), is required for the estimation of SRMC, while Fixed O&M (FOM) costs are required for new entrant costs and decisions relating to retirements of incumbent plant.

Variable O&M

The additional operating and maintenance 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.

For coal, VOM includes additional consumables such as water, chemicals and energy used in auxiliaries and incremental running costs such as ash handling.

For gas, in addition to consumables and additional operating costs, an allowance is also included for major maintenance. The reason for including an allowance for major maintenance in the VOM for gas turbines is because this maintenance is not periodic, as it is for coal plant, but rather is generally determined by hours of operation and specific events such as starts, stops, trips etc.

It is these additional starts that mean that an OCGT peaking plant has a higher VOM per MWh than either a CCGT base or intermediate load plant.

The VOM value is usually expressed in sent-out terms to account for internal usage by the station (see below) rather than in 'as generated' terms.

Table 4 **Variable operation and maintenance ($/MWh, real 2010-11)**

VOM (Real $/MWh)	2010-11
SC BLACK (AC)	1.26
SC BROWN (AC)	1.26
CCGT (AC)	1.10
OCGT	7.88
Wind	1.84
Hydro	7.50
Geothermal (HDR)	2.10
Biomass	4.93

Note: AC refers to air-cooled power stations
Data source: ACIL Tasman forecasts

Fixed O&M

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, fixed O&M 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.

Table 5 **Fixed operation and maintenance costs ($/MW/year, real 2010-11)**

FOM (Real $/MW/year)	2010-11
SC BLACK (AC)	50,430
SC BROWN (AC)	57,784
CCGT (AC)	32,569
OCGT	13,658
Wind	21,538
Hydro	53,581
Geothermal (HDR)	36,772
Biomass	52,038

Note: AC refers to air-cooled power stations
Data source ACIL Tasman forecasts:

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) and also in GJ/MWh.

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 or LHV) are the appropriate measures to calculate fuel use and the marginal costs of generation.[3]

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 6 **Thermal efficiencies (HHV, sent-out values)**

	2010-11
SC BLACK (AC)	40.0%
SC BROWN (AC)	32.0%
CCGT (AC)	50.0%
OCGT	31.0%
Wind	100.0%
Hydro	100.0%
Geothermal (HDR)	100.0%
Biomass	30.0%

Note: AC refers to air-cooled power stations
Data source: ACIL Tasman forecasts

[3] 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.

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.

Table 7 **Availability %**

	2010-11
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 Auxiliaries

Auxiliary load is used within a power station as part of the electricity generation process (also called a parasitic load). The usual way of expressing the station auxiliaries is as a percentage applied to the gross capacity of the station, providing a measure of the net capacity or sent-out capacity of the station.

Station auxiliaries also affect the sent-out or net thermal efficiency of the station, and therefore the station's SRMC.

Table 8 **Auxiliary use of energy (%)**

	2010-11
SC BLACK (AC)	7.5%
SC BROWN (AC)	9.5%
CCGT (AC)	2.4%
OCGT	2.0%
Wind	0%
Hydro	0%
Geothermal (HDR)	0%
Biomass	0%

Note: AC refers to air-cooled power stations
Data source: ACIL Tasman forecasts

2.3.6 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 forecast of fuel costs prepared for the LRMC modelling is shown in Table 11. The forecasts are based on the ACIL Tasman's April 2009 report to the IRPC of NEMMCO. 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.

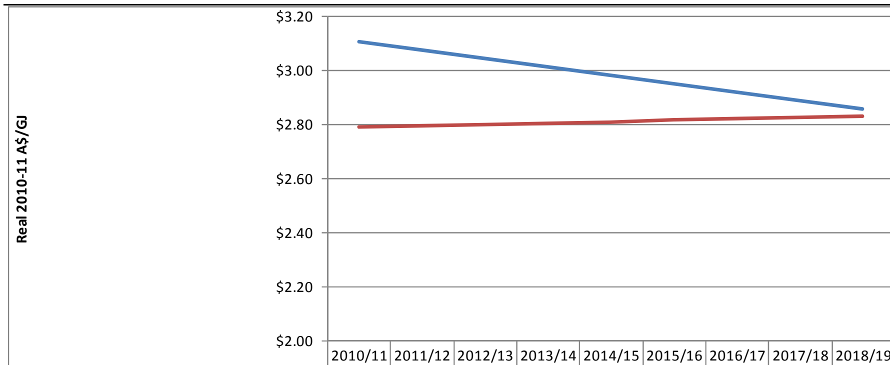
Coal

Coal prices have been taken from the April 2009 report to NEMMCO except in the cases where changes in exchange rates since the completion of that report have materially changed the price outlook for thermal coal. The forecast for coal prices into the Victorian power stations, which are not influenced by export prices, have not been changed from the April 2009 NEMMCO report. The greenfields calculation of the LRMC results in no coal fired power in South Australia so coal prices in that NEM region are not necessary.

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. We assume that as coal contracts are renewed in the new contract, the price is set at 80% of the netback export price. Most of the power stations affected by export coal prices are in NSW but some are also located in Queensland. This netback export price has changed significantly since April 2009 because of the appreciation of the Australian dollar against the currencies of Australia's major coal trading partners.

The revised forecast of free on board (fob) export prices for thermal coal is shown in Figure 1. The revision mainly affects the 2010-11 starting price of coal and involves reducing fob coal prices by the amount implied by the recent appreciation of the Australian dollar against the US dollar. Over time we have assumed that the exchange rate returns to its long term average and the fob Australian dollar price reaches a similar level in both forecasts by 2018-19.

Figure 1 **Forecasts of fob price of thermal coal (real 2010-11 A$/GJ)**



	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19
Used in NEMMCO Report	$3.10	$3.07	$3.04	$3.01	$2.98	$2.95	$2.92	$2.88	$2.85
Revised for calculation of 2010/11 BRCI	$2.79	$2.79	$2.80	$2.80	$2.81	$2.81	$2.82	$2.82	$2.83

Data source: AT 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 the LRMC. However Swanbank B, Collinsville and Tarong, which have largely exhausted their existing supply sources, have been excluded from the Queensland average. All power stations in NSW have been included.

The forecast coal prices into the NSW power stations are shown in Table 9. 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 (real; 2010-11 A$/GJ)**

	Macquarie Generation	Eraring Energy	Delta Coastal	Delta Western	Redbank
2010/11	$1.26	$1.65	$1.65	$1.75	$1.03
2011/12	$1.25	$1.65	$1.65	$1.74	$1.03
2012/13	$1.31	$1.65	$1.65	$1.73	$1.03
2013/14	$1.31	$1.65	$1.65	$1.65	$1.03
2014/15	$1.31	$1.68	$1.65	$1.30	$1.02
2015/16	$1.30	$1.68	$1.65	$1.31	$1.02
2016/17	$1.30	$1.68	$1.65	$1.31	$1.02
2017/18	$1.30	$1.70	$1.65	$1.32	$1.02
2018/19	$1.30	$1.71	$1.65	$1.32	$1.01

Data source: ACIL Tasman analysis

The forecast coal prices into Queensland existing coal stations used in the Queensland coal price used in the LRMC modelling are shown in Table 10.

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 (real; 2010-11 A$/GJ)**

	Gladstone	Stanwell	Callide B & C	Millmerran	Kogan Creek
2010/11	$1.60	$1.43	$1.35	$0.87	$0.77
2011/12	$1.59	$1.42	$1.34	$0.87	$0.76
2012/13	$1.59	$1.42	$1.34	$0.86	$0.76
2013/14	$1.58	$1.41	$1.34	$0.86	$0.76
2014/15	$1.58	$1.41	$1.33	$0.86	$0.76
2015/16	$1.58	$1.41	$1.33	$0.86	$0.76
2016/17	$1.57	$1.40	$1.33	$0.85	$0.75
2017/18	$1.57	$1.40	$1.32	$0.85	$0.75
2018/19	$1.57	$1.40	$1.32	$0.85	$0.75

Data source: ACIL Tasman analysis

Natural gas

Long-term price projections for gas included in Table 11 have been provided as output from our proprietary gas market model – *GasMark*. GasMark incorporates a complete input database containing data and assumptions for every gas producing field, transmission pipeline and major load/demand centre in Australia. It is used by ACIL Tasman internally, and is also licensed to a number of external gas market participants.

GasMark provides price projections for each defined node on the Eastern Australian gas grid.

The availability of gas to support generation in each NEM region is determined by a number of factors, namely:

- The reserves and production capability of various fields (locally and in an aggregate sense throughout Eastern Australia)
- Existing transmission capacity into the region (if the region does not have sufficient gas resources)
- The potential for new or additional transmission capacity.[4]

[4] The planning and development of additional pipeline capacity is generally shorter than the station itself and therefore does not impact upon the lead-time for gas plant development.

The assumptions used in this forecast include the development of two LNG export facilities of 4 Mtpa each, with assumed start-up in 2014 and 2018.

On the demand-side the outlook includes assumed growth in domestic demand, both through large industrial loads and general growth in reticulated gas to residential and commercial premises. The total assumed growth in gas demand – excluding NEM-scheduled power generation – is relatively modest at around 130 PJ/a (growth rate of 2.6% per annum).

The supply assumptions include all existing and known, but undeveloped field developments and an assessment of undiscovered conventional and yet-to-be certified CSG resources.

Table 11 shows the projected delivered gas prices for new CCGT and OCGT plant in each NEM region in real 2010-11 $/GJ. For CCGT plant the delivered cost assumes a gas load factor of 80% (for transportation costs). Prices for OCGT plant are at a premium to CCGT costs, reflecting higher transportation and commodity costs for low gas load factor users.

Prices in 2010-11 reflect a significant premium over historical gas prices under existing contracts. This reflects the existing state of the market, whereby significant upstream consolidation has occurred and those players that remain are primarily focussed upon developing LNG export projects.

Prices are projected to increase slightly in real terms, converging to what could be considered a new long term equilibrium level with the inclusion of significant LNG export facilities.

The appreciating A$ to US$ exchange rate over the past 12 months does not have the same significance for forecast gas prices as it does for the coal price forecast. Gas prices are determined mostly within the domestic market and the influence of east coast LNG exports is that it removes gas reserves from the domestic supply picture, thereby causing higher cost reserves to be called upon to meet the domestic market.

Table 11 **Fuel costs (AUD/GJ, real 2010-11)**

	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19
Biomass	1.74	1.74	1.74	1.74	1.74	1.74	1.74	1.74	1.74	1.74
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Hydro	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
New Black Coal NSW	1.47	1.47	1.48	1.46	1.40	1.40	1.40	1.40	1.40	1.47
New Black Coal QLD	1.20	1.20	1.20	1.19	1.19	1.19	1.19	1.18	1.18	1.20
New Brown Coal VIC	0.60	0.59	0.59	0.59	0.59	0.59	0.59	0.59	0.58	0.60
New CCGT NSW	5.80	5.76	5.76	5.77	5.79	5.80	5.84	5.92	6.01	5.80
New CCGT QLD	4.82	4.84	4.87	4.89	4.91	4.93	4.95	4.97	4.99	4.82
New CCGT SA	5.30	5.33	5.49	5.65	5.82	5.99	6.06	6.22	6.37	5.30
New CCGT TAS	5.55	5.58	5.60	5.62	5.80	5.97	6.04	6.21	6.36	5.55
New CCGT VIC	4.70	4.73	4.75	4.78	4.95	5.13	5.20	5.36	5.52	4.70
New OCGT NSW	7.24	7.20	7.19	7.22	7.24	7.25	7.30	7.40	7.51	7.24
New OCGT QLD	6.02	6.05	6.08	6.11	6.14	6.17	6.19	6.21	6.24	6.02
New OCGT SA	6.62	6.66	6.86	7.06	7.27	7.49	7.58	7.77	7.96	6.62
New OCGT TAS	6.94	6.97	7.00	7.03	7.25	7.47	7.56	7.76	7.95	6.94
New OCGT VIC	5.88	5.91	5.94	5.97	6.19	6.41	6.50	6.70	6.89	5.88
Wind	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Data source: ACIL Tasman forecasts

2.3.7 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.

2.3.8 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:[5]

- 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

[5] It should be noted that each of these formulas are equivalent if the analysis is performed on a pre-tax basis.

target post-tax WACC because it is commonly used for asset valuation and project evaluation.

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, one must then make assumptions 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 **9.48%.**

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%, giving a post-tax real WACC of **6.81%.** This WACC ids the same as used in the Draft Decision.

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.

In its response to the 2010-11 BRCI Draft Decision, AGL suggested that ACIL Tasman's new entrant LRMC model applied immediate utilisation of the interest tax shield and as such may not be consistent with the BRCI framework assumption of a stand-alone, project-financed new entrant LRMC. ACIL Tasman contends that its approach correctly defines a generic greenfield project and is consistent with the BRCI framework. Incorporating the interest tax shield effects into the WACC rather than the cash flows provides for a generic greenfield new entrant with the tax shield effect spread over the project life rather than on a year by year basis.

For the Final Decision ACIL Tasman has updated selected WACC parameters used for the Draft Decision in November 2009.

The risk free rate has been updated by taking the average daily yield over a 90 period on long term commonwealth bonds maturing between 2014 and 2020 and using the average of these yields as long term risk free rate. The yields were sourced from RBA data[6].

The updated 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 a recent decision (on gas distribution) the AER[8] selects a debt basis point premium of 335. ACIL Tasman has used a debt basis premium of 300 points in calculating the WACC for the calculation of the 2010-11 BRCI Final decision. This compares with 200 debt basis points premium in used in calculating the WACC for the Draft Decision.

---

[6] RBA, "Indicative Mid Rates of Selected Commonwealth Government Securities", sourced on 21 April 2010.

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

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

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% in this report for the Final Decision (the same as the figure used in the report for the Draft Decision) for the market risk premium.

Other parameters used for the Final Decision have been kept at the same levels as in the report for the Draft Decision.

Table 12 **WACC parameters**

	Parameter	Draft Decision	Final Decision
D+E	Liabilities	100%	100%
D	Debt	60%	60%
E	Equity	40%	40%
rf	Risk free RoR	6.0%	5.43%
MRP = (rm-rf)	Market risk premium	6.0%	6.0%
rm	Market RoR	12.0%	12.0%
T	Corporate tax rate	30%	30%
Te	Effective tax rate	22.5%	22.5%
	Debt basis point premium	200	300
rd	Cost of debt	8.0%	8.0%
G	Gamma	0.50	0.50
ba	Asset Beta	0.80	0.80
bd	Debt Beta	0.16	0.16
be	Equity Beta	1.75	1.75
re	Required return on equity	16.5%	16.5%
F	Inflation	2.50%	2.50%

The changes to the risk free RoR and the debt basis point premium between the Draft and Final decision. The changes have not altered the final WACC used in the LRMC for the Final Decision compared with the Draft Decision. The lower risk free RoR is offset by the higher debt basis point premium.

2.3.9 The Average Loss Factor (ALF)

The electricity generated and sent out by power stations is paid for at the Regional Reference Node. 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 ALF.

The ALF has been calculated in a similar way to previous years. Powerlink's Annual Planning Review, 2009, on page 31 provides a forecast of 2010-11 Queensland transmission losses (1,947GWh) and sent-out energy (52,629GWh) and dividing the former by the latter gives a forecast ALF of 3.7%.

2.4 Methodology

In calculating the 2010-11 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 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 2010-11 to 2018-19 inclusive (nine years) – the same as the projection horizon adopted in previous years by CRA in their calculation for the BRCI. 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.

For example, the projection of fuel prices in the LRMC model includes strong increases in gas prices in the second half of the nine years. New entrants looking only three years ahead therefore require lower demand-weighted RRPs to make their required return (keeping in mind this is a temporal model). We believe it is more realistic and rational for potential new entrants to take in to account any material and widely expected market changes, such as an increase in gas prices due to increased demand for LNG and electricity generation.

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.

Having said this, the LRMC modelling does not explicitly include any changes that might follow from the introduction of an emissions trading scheme (ETS) in Australia. There are a number of reasons for this. Firstly, the ETS is only proposed at present and while the introduction of a scheme to reduce CO_2 emissions appears likely at some time in the future, the precise form of such a scheme is still unknown. The date of introduction and the price of emissions permits are very uncertain and we have opted to exclude the effects of pricing emissions from the LRMC modelling given the high levels of uncertainty surrounding the parameters.

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 2009 from the AEMO website. The Draft Decision was based on NEM regional load traces for the year to 30 September 2009. This is the only difference in the LRMC calculation between the Draft and Final Decisions.

There is a noticeable difference in the load trace for Queensland between Q4 2009 used in the Final Decision and Q4 2008 used in the Draft Decision. Q4 2009 had noticeably higher demands that Q4 2008 which explains any difference between the LRMC used in the Draft Decision compared with the LRMC used in the Final Decision.

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.

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).

This appears to be similar to the approach taken in previous years by CRA although they used a sample of 40 regional demands instead of 50. We believe this does not make a material difference in the way the models treat demand.

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 2010-11 and 2018-19 inclusive based on the forecasts of annual regional maximum demand and regional energy use published in the 2009 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. Based on our reading of previous BRCI reports we understand this is to be similar to the approach used in previous years.

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 2009 Annual Planning Review.

2.4.2 Using the 2009 AEMO medium economic forecast

In its comment addressing the *Draft Decision Benchmark Retail Cost Index for Electricity: 2010-11 (Draft Decision)*, AGL has noted

> "…that by using the medium economic forecast, the demand forecasts used in the modelling are understated"

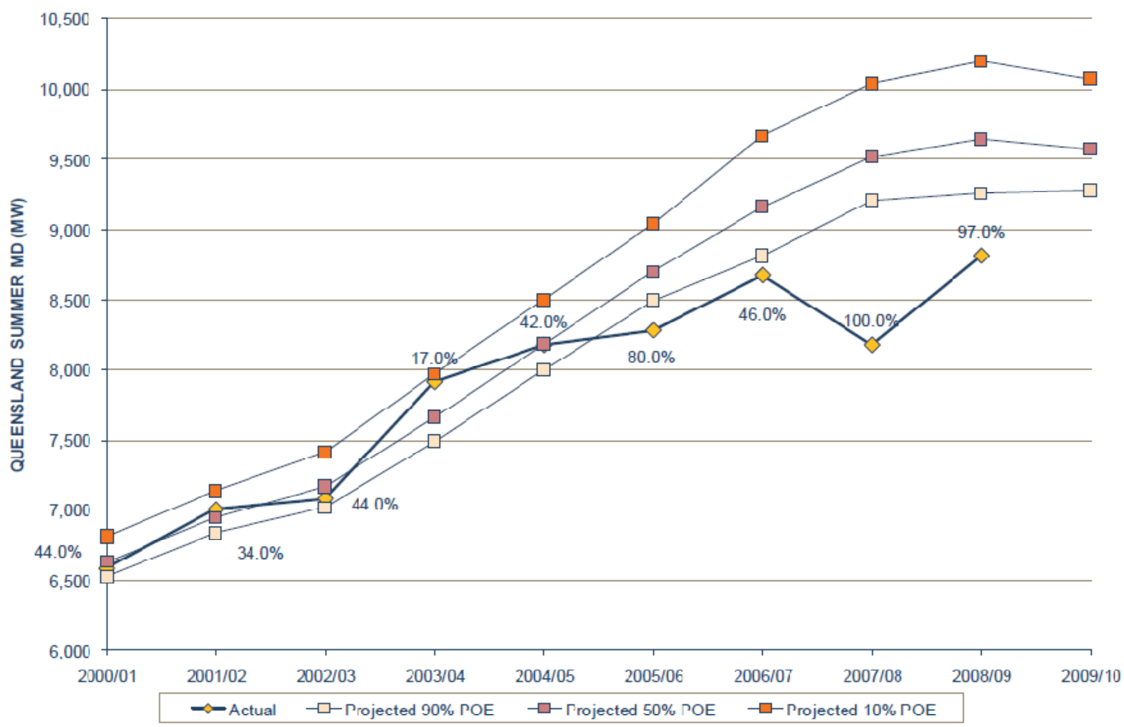
> "…these forecasts are overly pessimistic having been compiled at the time of the Global Financial Crisis and do not reflect the improved economic conditions in Australia that have resulted since".

In recent history, the maximum demand (MD) forecasts provided by AEMO for Queensland have been significantly higher compared to the observed values (see Figure 2). The AEMO have acknowledged that

> "values projected for 2007-08 and 2008-09 missed an apparent slowing in actual MD and energy growth".

This was due to the implemented methodology, which used a 10-year rolling average of historical diversity factors to develop the Queensland 50% POE MD projection, which has a highly variable intra-regional diversity.

Figure 2 **Queensland summer MD one-year-out back assessment**

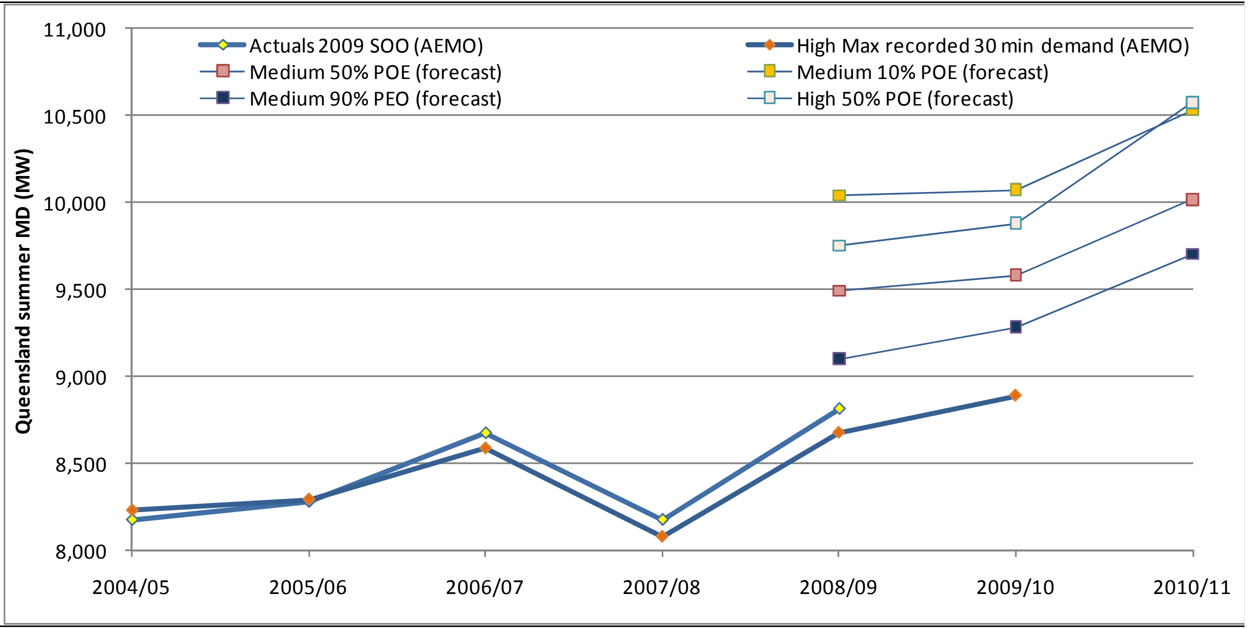


Source: AEMO 2009 ESOO, Appendix C, Figure C.1, pp. C6

Note: the percentages attaching to each actual MD refer to the POE level for the maximum daily temperatures that coincide with annual MD

The AEMO goes on to note that "the latest forecasts are more in line with the apparent actual trends". Nevertheless, Queensland's 2009-10 MD actuals are still significantly below those published in the AEMO 2009 ESOO (see Figure 3). This is despite hotter actual peak temperatures compared with the 50% summer reference temperatures across the State.

Figure 3 **Queensland summer MD actuals and AEMO 2009 ESOO forecasts**



Source: AEMO 2009 ESOO, Market data AEMO 2010

Looking at other regions across the NEM a similar pattern can be observed. New South Wales and South Australia fell short of their respective AEMO 2009 ESOO medium 50% POE forecast, whereas Victoria and Tasmania were slightly above theirs.

Table 13 **NEM summer MD actuals and AEMO 2009 ESOO forecast**

Actuals for 2009/10 summer			Compared with 2009 AEMO Forecast			
	Year to March 2010		**Medium 50% POE**		**High 50% POE**	
	Observed Max	Date Occurred	2009/10	Difference	2009/10	Difference
NSW	13,765	22-Jan-10	14,445	680	14,485	720
Qld	8,891	18-Jan-10	9,582	691	9,881	990
SA	3,121	13-Feb-10	3,230	109	3,250	129
Tas	1,513	7-Oct-09	1,417	-96	1,457	-56
Vic	9,858	11-Jan-10	9,790	-68	10,048	190

Source: AEMO 2009 ESOO, Market data AEMO 2010

Finally, considering the underlying economic forecasts for all the NEM regions, the AEMO 2009 ESOO medium 50% POE forecast assumes a significant recovery for 2010-11 (see Table 14). The forecast assumes a faster recovery from the Global Financial Crisis compared to the more conservative estimate by the Federal Treasury.

Table 14 **Growth rate comparison between 2009-10 Federal Budget and AEMO 2009 ESOO**

Financial Year	Federal Budget	KPMG Medium	KPMG High	KPMG Low
2008/09	0	0.1	0.4	-0.1
2009/10	-0.5	-0.2	0.1	-1.0
2010/11	2.25	3.6	3.9	2.9
2011/12	4.25	3.3	3.7	3.0
2012/13	4.25	3.2	3.5	3.6
Average	2.1	2.0	2.3	1.7

Source: AEMO 2009 ESOO, Chapter 8, Table 8.6, pp. 8-6

Similarly, the forecast provided for Queensland in the AEMO 2009 ESOO assumes a significantly stronger recovery compared with other forecast estimates for 2010-11.

Based on the above ACIL Tasman believes that the most appropriate official forecast to use in the calculation of the 2010-11 BRCI for the Final Decision is the medium growth 50% POE forecast provided in the AEMO 2009 SOO.

2.4.3 Transmission

PowerMark LT includes the existing interconnectors and optimises the use of the interconnectors. 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.

2.4.4 Other factors

The modelling assumes the Queensland Gas Electricity Certificate (GEC) Scheme continues with GEC prices fixed at the penalty and the GEC target set at 15% for 2010-11. PowerMark LT subtracts the GEC price from the LRMC of gas-fired plant in Queensland – this deduction increases the attractiveness of these plant which results in more CCGT/OCGTs being included in the optimal plant mix of Queensland. However, if there is an oversupply of GECs then only the proportion of GECs able to be sold is included in the revenue streams. This has the effect of decreasing the amount of the reduction to the LRMC due to the GECs. For example, if Queensland generators produce twice as many GECs as are required to meet the annual target then the model will only reduce the LRMC of the CCGTs/OCGTs by 50% of the GEC penalty. The model undertakes several iterations to find a stable solution of gas-fired penetration. We believe this is similar to the approach taken in previous years.

The RET scheme is included with the REC price fixed at the penalty. We assume the RET scheme is satisfied and, similar to the treatment of GECs, the REC price is taken off the LRMC of the renewable plant in all regions.

2.5 Results

The results from the LRMC modelling used in the Draft and Final Decisions are shown in Table 15. The main differences in Queensland between the Draft and Final Decisions can be summarised as:

- slightly higher coal fired capacity and slightly lower CCGT and OCGT capacity
- higher capacity factor for OCGT and lower for CCGT
- slightly higher generation in Queensland due to higher exports to NSW.

All of these changes are due to the changed base load trace.

Table 15 **ACIL Tasman LRMC results**

	SRMC ($/MWh)	LRMC ($/MWh)	Plant capacity (MW)	Dispatch (GWh)	Capacity factor (%)	Market share (%)	Capacity share (%)
Draft Decision							
Coal	$12.09	$50.00	4,750	37,445	90%	63.8%	47.0%
CCGT	$29.97	$61.67	3,904	20,306	59.4%	34.6%	38.6%
OCGT	$77.78	$242.68	1,463	966	7.5%	1.7%	14.5%
Total			10,153	58,899		100.0%	100.0%
Final Decision							
Coal	$12.09	$50.00	4,995	39,381	90.0%	66.5%	49.3%
CCGT	$29.97	$61.67	3,687	18,844	58.3%	31.8%	36.4%
OCGT	$77.78	$242.68	1,441	1,032	8.2%	1.7%	14.2%
Total			10,123	59,256		100.0%	100.0%
% change							
Coal	0.0%	0.0%	5.2%	5.2%	0.0%	4.3%	5.0%
CCGT	0.0%	0.0%	-5.6%	-7.2%	-1.8%	-8.0%	-5.7%
OCGT	0.0%	0.0%	-1.5%	6.8%	8.8%	3.0%	-1.8%
Total			-0.3%	0.6%		0.0%	0.0%

Data source: ACIL Tasman modelling

The resultant LRMC of electricity in Queensland in 2010-11 for use in the Final Decision is **$58.59/MWh**. This takes into account an allowance of 3.7% to cover average transmission losses in the Queensland region of the NEM.

This result is slightly higher than $58.51 presented in the report for the Draft Decision. This is because the full year of 2009 hourly loads has been used instead of the year to 30 September 2009 used in the draft. The last quarter of 2009 had higher than average demand, particularly in Queensland, with a number of high temperature and high demand weeks and generation in the final calculation above was some 357GWh higher than in the report for the Draft Decision.

3 Energy purchase costs (EPC)

In order to maintain consistency in the methodology applied to the EPC calculation ACIL Tasman has followed CRA's methodology for the 2009-10 BRCI described in Section 3.3 of CRA's of their final report on *Calculation of the Benchmark Retail Cost Index 2009-10, 8 June 2009* (CRA report).

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 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 2010 from the load forecast in the AEMO 2009 ESOO.
- Using the load traces for the NEM regions, carry out simulation market modelling for the 2010-11 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 2010-11 by applying the retailer's contracting strategy developed in previous in previous years by CRA 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 2010-11 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 2010 to match the Powerlink 2009 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 2010 to match the AEMO 2009 ESOO forecasts for summer and winter peaks and annual energy for 2010-11.

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 which 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 2010-11 half hour RRPs needed to calculate the cost of energy.

The total (large) Queensland load and the NEM regional load forecast for 2010-11 are lined up on a half basis to ensure the loads and prices are totally 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 2010, as supplied by QCA, into the total load for Queensland including directly connected customer load.

Financial year load trace configurations for both total load for Queensland and the directly connected customer load are then produced by moving the June Quarter 2009 from the beginning to the end of the year to 31 March 2010 load traces.

The load traces for both total NEM regional load for Queensland and the directly connected customers are adjusted in precisely the same way so that they remain exactly comparable with each other for every half hour.

Load traces of "as generated" load for each NEM region using data to 31 March 2010 were also constructed in this way. These load traces were extracted from the AEMO website.

3.1.2 Load forecasts for Queensland and NEM Regions

The forecasts of the following items for 2010-11 are then extracted from the Powerlink 2009 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% 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 2009 ESOO to produce the NEM regional load traces used in the modelling of 2010-11 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 50POE, 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 akin to a linear programming solution.

The forecast half-hourly load trace for the total load in Queensland is produced for 2010-11 based on the load trace described above, and the medium growth 10%, 50% and 90% POE forecasts from the Powerlink 2009 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 the energy costs in the BRCI.

Table 16 presents the forecast minimum and maximum demand, energy and load factor from this load trace for 2010-11 used in the Draft and Final Decision.

Table 16 **Maximum and minimum demand (MW), energy (GWh) and load factor (%) – 2010-11 Draft and Final Decisions**

	Total Load (MW)			Directly Connected (DC) Load (MW)	NEM (small) load (MW)		
	10%POE	50%POE	90%POE		10%POE	50%POE	90%POE
Draft Decision							
Maximum demand (MW)	9,330	8,866	8,583	1,276	8,175	7,711	7,428
Minimum demand (MW)	3,907	3,907	3,907	480	2,820	2,820	2,820
Energy (GWh)	50,748	50,682	50,644	10,518	40,230	40,164	40,126
Load factor (%)	62.10%	65.30%	67.40%	94.10%	56.20%	59.50%	61.70%
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%
% Change							
Maximum demand	0.0%	0.0%	0.0%	3.4%	0.2%	0.2%	0.3%
Minimum demand	2.1%	2.1%	2.1%	67.6%	-0.6%	-0.6%	-0.6%
Energy	0.0%	0.0%	0.0%	3.3%	-0.9%	-0.9%	-0.9%
Load factor	0.0%	-0.1%	-0.1%	-0.1%	-1.1%	-1.2%	-1.2%

Data source: ACIL Tasman analysis based on Powerlink data

As expected there are only minor differences between the key load trace parameters for 2010-11 used in the Draft and Final Decisions as these are based on the same load forecast from the 2009 Powerlink APR.

In its response to the 2010-11 BRCI Draft Decision, AGL has queried the use of the medium growth 50%POE AEMO 2009 ESOO load forecast as the basis for the BRCI calculations. As discussed in Section.2.4.2 ACIL Tasman believes that the most appropriate official forecast to use in the calculation of the 2010-11 BRCI is the medium growth 50% POE forecast provided in the AEMO 2009 SOO.

3.2 Simulation market modelling for 2010-11

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 2010-11 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 2010-11.
- **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 2010-11 shows an outlook in which the electricity market is recovering from the effects of the recent drought, which increased spot prices significantly, and moving into a period where generation capacity has been increased and spot prices falling.

The drought reduced the generation from the Tarong and Swanbank B stations in Queensland, due to reduced access to cooling water, as well as reduced generation from the hydro stations in Snowy and Tasmania, due to very low storage levels.

By 2009 drought conditions have eased in Queensland and generation from the affected (non-hydro) stations has returned to normal levels. Further, the commissioning of Colongra, Eraring expansion, Tallawarra, Uranquinty, Braemar Two, Condamine, Darling Downs, Yarwun, Quarantine expansion, Tamar Valley, Bogong and Mortlake between 2009 and 2011 results in prices generally falling from their high levels in 2008 and early 2009.

Table 17 shows the quarterly RRPs from the market modelling for the 2010-11 year to be used in the Final Decision.

Table 17 **ACIL Tasman quarterly RRPs– 2010-11 Final Decision ($/MWh)**

	10%POE	50%POE	90%POE
Q3 2010	$35.59	$34.44	$31.67
Q4 2010	$70.07	$45.10	$34.64
Q1 2011	$57.53	$36.57	$31.34
Q2 2011	$31.55	$30.06	$28.06
Annual average	$48.68	$36.56	$31.44

Data source: ACIL Tasman PowerMark modelling

Settlement is modelled for three load scenarios – the 10%POE, the 50%POE and the 90%POE.

These RRPs are higher than the RRPs used in the Draft Decision. The RRP projection in Table 17 to be used in the Final Decision uses a base NEM regional load trace for the year to March 2010 whereas the projection used in the Draft Decision used a base NEM regional load trace for the year to 30 September 2009. The loads in Q4 2009 and Q1 2010 are noticeably higher than those in Q4 2008 and Q1 2009, which they replaced, and this has led to increases in the RRPs projected for Q4 2010and Q1 2011 to be used in the Final Decision.

The quarterly RRP changes between the Draft and Final Decisions are shown in Table 18. It shows the significant lift in the Q4 2010 RRP projection between the Draft and Final Decision due entirely to the changed NEM base load trace characteristics between Q4 2008 and Q4 2009. All generator costs and other inputs to the RRP modelling are identical in both the Final and Draft Decisions. As expected the 10%POE projection displays the greatest increase for Q4 2010 as many of the 400 higher half hourly demand points are now in Q4.

The pattern of quarterly prices in the Final Decision is consistent with recent history (compare the pattern in 2008-09 with that projected for 2010-11 in Figure 4).

Table 18 **Change in quarterly RRPs between Draft and Final Decisions ($/MWh)**

	10%POE	50%POE	90%POE
Q3 2010	-$5.09	-$2.71	-$2.26
Q4 2010	$40.22	$19.19	$9.47
Q1 2011	-$0.15	$7.55	$5.52
Q2 2011	-$0.65	-$1.89	-$1.59
Annual average	$8.66	$5.55	$1.79

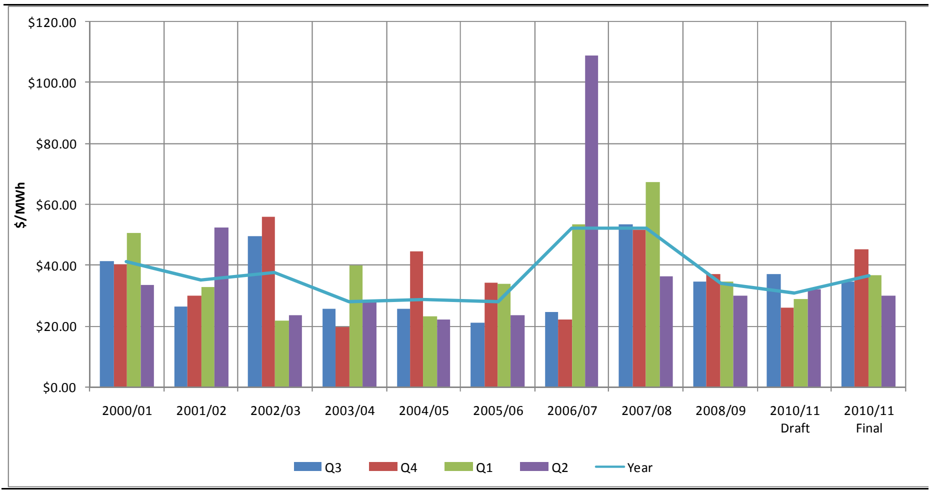
Data source: ACIL Tasman PowerMark modelling

3.3 Commentary on results of the RRP modelling

In their submissions on the 2010-11 BRCI Draft Decision both AGL and Origin have commented on the correlation in the results between high prices and low demand periods. AGL have noted that this result is generally contrary to market expectations with highest contract prices occurring in Q1 or Q4, that is, the warmer summer seasons.

This is a fairly consistent feature of the swap contract market but it is not such a consistent feature of quarterly RRPs. Figure 4 below shows quarterly and annual time weighted RRPs for the last nine financial years. In this period the Q1 price has been the highest quarterly price in only three years (2000-01, 2003-04 and 2007-08).

Figure 4 **Queensland quarterly and annual 50%POE regional reference prices ($/MWh, 2000-01 to 2008-09)**



Source: AEMO data

The price projection for 2010-11 is typical of a market in which the excess of capacity over demand is relatively high and prices in the warmer summer months, when all capacity is made available, are suppressed. Higher prices can occur in such a projection in Q2 or Q3, when baseload plant can be taken out for scheduled maintenance and an unscheduled outage, or several coincident unscheduled outages, can cause high prices. Sometimes this occurs when the load is not particularly high.

In the 2010-11 projection for the energy purchase cost for the 2010-11 BRCI Final Decision, the high temperatures leading to high demand periods in Q4 2009 result in high demand periods in the load trace for the 2010-11 year resulting in the highest prices during Q4 2010.

3.4 Contracting strategy and prices

In general ACIL Tasman has attempted to follow the contracting methodology developed by CRA and QCA in previous calculations of the BRCI, especially as the methodology has been discussed with stakeholders and appears to have become broadly agreed. As a consequence we have followed as closely as possible at this stage the contracting strategy outlined in CRA's June 2009 report (pages 60 and 61).

CRA assumed 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 were used in the calculation of both the 2008-09 and 2009-10 BRCI and have also been used by ACIL Tasman to calculate the 2010-

11 EPC. For each quarter the criteria used 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

CRA concluded that a prudent retailer is likely to purchase contracts to meet its customers' loads over a period of about two years. They assumed that a retailer represented in the calculation of the BRCI would also spread its purchases of energy contracts for each tariff year evenly over a period of two years, in advance of the tariff year for which the energy is being hedged. This was acknowledged as a simplification but reasonable in the circumstances.

We have assumed therefore, in common with previous years, that for calculation of the 2010-11 EPC contracts are purchased evenly over the period 1 July 2008 to 31 March 2010.

Table 19 shows estimated quarterly swap and cap contract volumes purchased for 2010-11 under this strategy used for the Draft and Final Decisions.

Table 19 **Quarterly swap and cap contract volumes – 2010-11 Draft and Final Decisions (MW)**

	Draft Decision			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 2010	4,301	1,186	1,320	4,276	1,172	1,331	-0.6%	-1.2%	0.9%
Q4 2010	4,912	1,300	1,450	4,646	1,854	1,413	-5.4%	42.6%	-2.6%
Q1 2011	5,182	1,356	1,558	4,840	1,711	1,565	-6.6%	26.2%	0.4%
Q2 2011	4,616	1,006	1,299	4,275	1,379	1,244	-7.4%	37.1%	-4.2%

Data source: ACIL Tasman analysis based on previous CRA analysis.

The peak contract volumes have increased markedly in Q4 2010 and Q1 2011. This occurred because Q4 2009 and Q1 2010 in base load traces used in the Final Decision have noticeably more loads close to the peak load than the Q42008 and Q1 2009 used in the Draft Decision. Having many more loads near the peak load has caused a large increase in the 90th percentile of peak time loads used for determining the peak contract volumes for the Final Decision.

The reductions in the flat contract volumes used in the Final Decision compared with those used in the Draft Decision is also associated with the changes in the base load traces affecting the 80th percentile of off peak loads used in determining the flat contract volume.

3.4.1 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 two year period prior to the beginning of the 2010-11 BRCI period.[9]

Data by 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 2008 up until 31 March 2010, which was the latest available data at the time of writing this report. For the period between 31 March 2010 and 30 June 2010, an average of the last two months was used. This is consistent with the methodology used in the 2009-10 BRCI.[10]

Table 20 shows estimated quarterly swap and cap contract prices for 2010-11. Generally the flat and peak swap contracts used in the Final Decision are slightly higher than those used in the Draft Decision while the cap contract prices are lower. This is due to the recent trends towards higher contract prices in the d-cypha Trade data.

Table 20 **Quarterly swap and cap contract prices – 2010-11 Draft and Final Decisions ($/MWh)**

	Draft Decision			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 2010	$36.61	$50.18	$4.89	$36.92	$50.47	$4.58	0.8%	0.6%	-6.3%
Q4 2010	$44.00	$64.02	$10.45	$45.12	$66.18	$10.06	2.6%	3.4%	-3.7%
Q1 2011	$65.31	$106.73	$26.05	$66.80	$110.39	$25.21	2.3%	3.4%	-3.2%
Q2 2011	$38.54	$47.45	$4.59	$39.03	$47.59	$4.56	1.3%	0.3%	-0.6%

Data source: ACIL Tasman analysis using d-cyphaTrade data

9 Based on the methodology for the 2009-10 BRCI on page 66 of the CRA report, *Calculation of the Benchmark Retail Cost Index 2009-10* (8 June 2009).

10 See pages 61- 62 and page 66 of the CRA report, *Calculation of the Benchmark Retail Cost Index 2009-10* (8 June 2009).

3.5 Settlement

In the settlement process the half hourly prices from the 2010-11 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 2010-11.

As described in Section 3.1 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 3.7, page 31 of the Powerlink's 2009 APR we took the transmission losses for 2010-11 (1,947GWh) and divided by the sent-out energy (52,629GWh), to get a loss factor of 3.7%. This is the same method as used in the 2009-10 BRCI and the same as the approach used in the LRMC calculation.

The results for 2010-11 are shown in Table 21. There are a number of changes between the Draft and Final Decisions of which the key ones are:

- base load trace with many more demands near the peak in Q4 and Q1
- the RRPs are noticeably higher overall but particularly in Q4 and Q1
- peak contract volumes noticeably higher and flat contract volumes lower
- flat and peak contract prices slightly higher.

This has resulted in:

- noticeably higher pool costs
- reduced swap difference payments
- higher cap payments because of the greater number of demands nearer the peak demand

Table 21 **Contract settlement for the 10%, 50% and 90% POE for 2010-11 Draft and Final Decisions**

2010-11	10% POE	50% POE	90% POE
Draft Decision			
Total MWh	40,229,815	40,163,908	40,125,710
Total pool costs $	$1,943,700,542	$1,371,938,436	$1,239,533,052
Swap difference payments $	-$334,189,612	$794,019,542	$910,607,988
Cap premiums $	$136,668,104	$136,668,104	$136,668,104
Cap payments $	-$132,501,203	-$32,665,732	-$13,230,051
Total energy purchase cost $	$2,282,057,055	$2,269,960,350	$2,273,579,095
Total energy purchase cost $/MWh	$56.73	$56.52	$56.66
Total energy purchase cost (including ALF) $/MWh	$58.82	$58.61	$58.76
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
% Change			
Total MWh	-0.9%	-0.9%	-0.9%
Total pool costs $	29.6%	24.8%	13.2%
Swap difference payments $	-41.2%	-38.2%	-15.2%
Cap premiums $	4.3%	4.3%	4.3%
Cap payments $	79.8%	208.4%	248.7%
Total energy purchase cost $	-2.5%	-1.2%	-0.1%
Total energy purchase cost $/MWh	-1.6%	-0.3%	0.8%
Total energy purchase cost (including ALF) $/MWh	-1.6%	-0.3%	0.8%

ACIL Tasman calculation

Table 22 shows the estimated cost of purchasing energy for the 2010-11 BRCI period.

The weighted energy purchase cost in 2010-11 to be used for the Final Decision is **$58.51/MWh**. This is very similar to the $58.72/MWh used in the Draft Decision meaning the positive influences in the modelling have been almost exactly offset by the negative factors.

Table 22 **Energy purchase costs for 2010-11, scenario results, weightings and weighted values ($/MWh)**

	Scenario weighting	Draft Decision 2010-11	Final Decision 2010-11	Change
Energy purchase costs ($/MWh) - 10POE	30.40%	$58.82	$57.88	-$0.94
Energy purchase costs ($/MWh) - 50POE	39.20%	$58.61	$58.44	-$0.17
Energy purchase costs ($/MWh) - 90POE	30.40%	$58.76	$59.23	0.47
Energy purchase costs ($/MWh) - Weighted		$58.72	**$58.51**	-$0.21

Data source: ACIL Tasman analysis

Table 22 shows that there is small change in the EPC between the Draft and Final Decisions. This has occurred because the higher RRPs particularly in Q4 2010 and Q1 2011 used in the Final Decision (see Table 18) have noticeably increased the pool cost but reduced the swap difference payments by a similar amount. The reduction in swap difference payments occurs because the higher RRPs used in the Final Decision are generally closer to contract prices than was the case in the Draft Decision.

4 Other energy costs

ACIL Tasman has estimated other energy costs for the 2010-11 BRCI. Again we have borrowed heavily from the previous approach to these calculations given the need to maintain a consistent methodology combined with the fact that the approach has been canvassed with QCA and other stakeholders.

4.1 Renewable Energy Target scheme

To determine the costs to retailers of complying with the RET scheme, ACIL Tasman has used the published Renewable Power Percentage (RPP) for 2010 and the estimated RPP for 2011 based on the targets under the expanded RET. Using weekly market prices for RECs published by AFMA, we have calculated average REC prices of $47.73/MWh in 2010 and $44.81/MWh in 2011 using the averaging methodology found in the CRA report[11]. The average REC price is then multiplied by the RPP to get the cost of compliance with the RET in $/MWh.

Based on the approach discussed above, we estimate the cost of complying with the RET scheme to be $115 million for the NEM load in Queensland or **$3.05/MWh** in 2010-11 for the Final Decision. This estimate is based on a steep increase in the RPP which in turn is a result of the higher Renewable Energy Target in 2010-11 and a 50% increase in the amount of partial exemption certificates for energy intensive trade exposed (EITE) customers. The $3.05/MWh REC allowance used in the Final Decision is only marginally higher than the $3.01/MWh used in the Draft Decision for 2010-11.

While the average REC prices for 2010 and 2011 from AFMA are lower than used in the Draft Decision, the average RPP for 2010 (actual) and 2011 (estimate) is higher than used in the Draft Decision thereby resulting in a slight increase of $0.04/MWh in the REC cost used in the Final Decision compared to that used in the Draft Decision. As mentioned above the estimate of the RPP for 2011 includes a 50% increase in the allowance in the load for EITE industries, which are only partially subject to the RET.

Table 23 shows the estimated cost of RET in 2010-11 for the Draft and Final Decisions.

[11] See page 111 of the CRA report, *Calculation of the Benchmark Retail Cost Index 2009-10* (1 December 2009).

Table 23 **Estimated cost of the Renewable Energy Target - Draft and final decisions ($/MWh)**

	Draft Decision			Final Decision		
	2010	2011	Cost of RET 2010-11	2010	2011	Cost of RET 2010-11
RPP %	5.53%	6.98%		5.98%	7.25%	
Average REC price $/MWh	$49.57	$47.04		$47.73	$44.81	
Cost of RET	$2.74	$3.28	$3.01	$2.85	$3.25	**$3.05**

Data source: ACIL Tasman analysis based on AFMA price data and ORER for the 2010 RPP

In response to the Draft Decision, the Queensland Government suggested market prices be used to calculate the 2010-11 REC prices and claimed that ACIL's REC price estimate ($49.57/MWh for 2010 and $47.04/MWh for 2011) was above REC spot prices observed in 2009. The average REC prices to be used in the Final Decision as quoted above are of $47.73/MWh in 2010 and $44.81/MWh in 2011are found by averaging the actual REC prices for the respective calendar year in accordance with the adopted methodology. The reduction in the average REC prices in the Final Decision is due to the inclusion of lower prices in the six months to March 2010 which were not available for the Draft Decision. We are satisfied that the methodology provides a realistic estimate of REC purchase costs to apply in the respective years as it allows the RECs to be acquired over the previous one to two years.

In its response to the Draft Decision, AGL argued the LRMC of renewable generation in the determination of REC costs rather than market based costs. AGL believed that the LRMC approach provided a better representation of the costs that a retailer would have to pay for the majority of its REC purchases.

The Draft and Final Decisions have been based on the adopted methodology which relies on REC market prices *inter alia* to estimate REC costs in the short term. ACIL Tasman is of the view that the adopted methodology provides a sound basis for estimating REC costs in this short time frame and there would seem little justification for adopting a significant change in methodology as suggested by AGL. Furthermore, while it is possible to forecast the LRMC of renewable energy projects, any REC price forecast using on this LRMC would also be dependent on very uncertain assumptions regarding the introduction of the CPRS and the subsequent emissions prices. On this basis, we think that estimating REC prices using actual market data continued to present the most practical way of estimating REC costs, especially over a shorter term as required under the BRCI.

AGL has also suggested that the estimate of the RPP used in the Draft Decision, by not taking into account the part exemption of the Emission Intensive Trade Exposed (EITE) customers, will reduce the RPP and suggest a lower burden on electricity retailers. This claim by AGL is incorrect; ACIL

Tasman did take EITE customer exemptions into consideration in calculation the RPP for 2010 and 2011.

Since the Draft Decision the RPP of 5.98% for 2010 has been released and as provided in the *Renewable Energy (Electricity) Act 2001* it is assumed to include allowance for EITE customers. We had used an estimated RPP for 2010 of 5.53% in the report for the Draft Decision. This has led to a revision to the estimated 2011 RPP from 6.98% used in the Draft Decision to in the 7.25% to be used in the Final Decision. The large increase in RPP is partly due to an increase in the RET and a partly to a 50% increase in the amount of partial exemption certificates for EITE customers.

4.2 Queensland Gas Scheme

The costs to retailers of complying with the Queensland Gas Scheme are based on the penalty price to retailers for not surrendering sufficient Gas Electricity Certificates (GECs). Based on forecast CPI inflation in 2010-11 of 3.13%[12], the (tax effective) penalty price in 2011 is calculated to be $19.23/MWh.

On the basis that GECs account for 15% of retail load in 2011, the average cost to a retailer is $2.88/MWh in 2011. The 2010 costs in the report for the Draft Decision have also been updated using the 2009 published shortfall cost of $12.75/MWh and escalating this by the forecast inflation for 2009-10 of 2.3%. ACIL Tasman estimates the average figure for 2010-11 to be $107 million or $2.84/MWh. This compares with $105 million or $2.80/MWh used in the Draft Decision.

Table 24 shows the cost of GEC scheme estimates for 2010 and 2011 and the averages for 2010-11 for the Draft and Final Decisions.

Table 24 **Estimated cost of Queensland Gas Scheme – Draft and Final Decisions ($/MWh)**

	Draft Decision			Final Decision		
	2010 estimate	2011 estimate	Draft Decision 2010-11	2010 estimate	2011 estimate	Final Decision 2010-11
Shortfall charge	$12.90	$13.19	$13.05	$13.05	$13.46	$13.26
Tax-effective shortfall charge	$18.43	$18.84	$18.64	$18.65	$19.23	$18.94
Prescribed percentage	15%	15%	15%	15%	15%	15%
Total cost of Queensland Gas Scheme	$2.76	$2.83	$2.80	$2.80	$2.88	**$2.84**

Data source: ACIL Tasman analysis, RBA Statement on Monetary Policy May 2010, and QLD DEEDI for the 2010 shortfall charge.

12 Estimated according to CRA's methodology of averaging the RBA forecast CPI inflation figures for the years ending June 2010 and June 2011, using the forecasts from *RBA Statement on Monetary Policy, May, 2010*

4.3 NEM fees

Participant and FRC fees are payable to AEMO to cover operational expenditure. CRA's method for estimating NEM fees for 2009-10 was to apply a linear trend to total costs for each component of NEM fees and the load used to determine the $/MWh fee over the period since 2004-05.

ACIL Tasman has referred to AEMO's draft decision on NEM fees for 2010-11. NEM participant fees are budgeted at $0.28/MWh for both Draft and Final decisions. FRC fees are budgeted to fall to $0.06/MWh in the Final Decision compared with $0.09/MWh in the Draft Decision. Overall NEM fees decrease by about $0.03/MWh or 8.1% compared to the Draft Decision.

Table 25 compares the NEM fees estimates for 2010-11 for Draft and Final Decisions.

Table 25 **Estimated NEM fees – Draft and Final Decisions ($/MWh)**

Cost category	Draft Decision 2010-11	Final Decision 2010-11	% change
Market participant fees	$0.28	$0.28	0.0%
FRC fees	$0.09	$0.06	-33.3%
Total NEM fees	**$0.37**	**$0.34**	-8.1%

Data source: ACIL Tasman analysis based on the AEMO draft decision on NEM fees for 2010-11

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 31 March 2010 for the Final Decision), it is estimated that the cost of ancillary services will be $0.39/MWh in 2010-11, or in total $14.7 million. This is lower than the $0.45/MWh in the Draft decision due to the lower ancillary service costs in the six months to 31 March 2010 which were used in the estimate for the Final decision but not for the Draft Decision

Table 26 compares the Ancillary Services charges estimates for 2010-11 for Draft and Final Decisions.

Table 26 **Estimated ancillary services charges – Draft and final decisions ($/MWh)**

	Draft decision 2010-11	Final decision 2010-11	% change
Ancillary services	$0.45	$0.39	-13.3%

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 2010-11 Final Decision are estimated to be $251 million or $6.62/MWh, a decrease of 1.5% compared to the Draft Decision. Table 27 compares the other energy cost estimates to be used for 2010-11 Final Decision with the estimates used for the Draft decision.

Table 27 **Summary of other energy costs – Draft and Final Decisions ($/MWh)**

Cost category	Draft Decision 2010-11	Final Decision 2010-11	% change
Renewable Energy Target	$3.01	$3.05	-1.0%
Queensland Gas Scheme	$2.80	$2.84	1.4%
NEM fees	$0.37	$0.34	-8.1%
Ancillary services	$0.45	$0.39	-13.3%
Total other energy costs	**$6.63**	**$6.62**	**-1.5%**

Data source: ACIL Tasman analysis based on AFMA data, AEMO data and the CRA report

A Electricity market modelling for 2010-11

This Appendix provides the input data and assumptions for the PowerMark electricity market modelling used to provide RRPs for each half hour in 2010-11. 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**

Generator	DUID	From Date	To Date	Gen Type	Fuel	Unit Size (MW)	MinGen (MW)	Contract cover (MW)	Aux (%)	Thermal efficiency (HHV sent-out, %)	Emission factor (t CO2/GJ)	Emission factor sent-out (tCO2/MWh)	Var O&M (2009 AUD/MWh, sent-out)
Redbank Power Station	REDBANK1	1/01/2009		Steam turbine	Black coal	150	95	135	8.0%	29.3%	0.09	1.11	$1.18
Colongra	COLONGRA_1	1/12/2009		Gas turbine	Natural gas	332	0	0	3.0%	32.0%	0.0513	0.58	$9.98
Colongra	COLONGRA_2	1/12/2009		Gas turbine	Natural gas	332	0	0	3.0%	32.0%	0.0513	0.58	$9.98
Mt Piper Power Station	MP1	1/01/2009		Steam turbine	Black coal	660	280	570	5.0%	37.0%	0.0874	0.85	$1.31
Mt Piper Power Station	MP2	1/01/2009		Steam turbine	Black coal	660	280	570	5.0%	37.0%	0.0874	0.85	$1.31
Munmorah Power Station	MM3	1/01/2009		Steam turbine	Black coal	300	130	130	7.3%	30.8%	0.0903	1.06	$2.18
Munmorah Power Station	MM4	1/01/2009		Steam turbine	Black coal	300	130	130	7.3%	30.8%	0.0903	1.06	$2.18
Vales Point B Power Station	VP5	1/01/2009		Steam turbine	Black coal	660	250	480	4.6%	35.4%	0.0898	0.91	$1.18
Vales Point B Power Station	VP6	1/01/2009		Steam turbine	Black coal	660	250	480	4.6%	35.4%	0.0898	0.91	$1.18
Wallerawang C Power Station	WW7	1/01/2009		Steam turbine	Black coal	500	250	400	7.3%	33.1%	0.0874	0.95	$1.31
Wallerawang C Power Station	WW8	1/01/2009		Steam turbine	Black coal	500	250	400	7.3%	33.1%	0.0874	0.95	$1.31
Bendeela No. 1 Pump	SHPUMP	1/01/2009		Pump	Pump	240	0	0	1.0%	100.0%	0	0.00	$9.23
Eraring Power Station 330kv	ER01	1/01/2009		Steam turbine	Black coal	660	210	500	6.5%	35.4%	0.0895	0.91	$1.18
Eraring Power Station 330kv	ER02	1/01/2009		Steam turbine	Black coal	660	210	500	6.5%	35.4%	0.0895	0.91	$1.18
Eraring Power Station 500kv	ER03	1/01/2009		Steam turbine	Black coal	660	210	500	6.5%	35.4%	0.0895	0.91	$1.18
Eraring Power Station 500kv	ER04	1/01/2009		Steam turbine	Black coal	660	210	500	6.5%	35.4%	0.0895	0.91	$1.18
Hume Power Station NSW	HUMENSW	1/01/2009		Hydro	Hydro	29	5	0	1.0%	100.0%	0	0.00	$6.15
Shoalhaven Bendeela Power Station	SHGEN	1/01/2009		Hydro	Hydro	240	0	30	1.0%	100.0%	0	0.00	$9.23
Bayswater	BW01	1/01/2009		Steam turbine	Black coal	680	310	400	6.0%	35.9%	0.0902	0.90	$1.18
Bayswater	BW02	1/01/2009		Steam turbine	Black coal	680	310	400	6.0%	35.9%	0.0902	0.90	$1.18
Bayswater	BW03	1/01/2009		Steam turbine	Black coal	680	310	400	6.0%	35.9%	0.0902	0.90	$1.18
Bayswater	BW04	1/01/2009		Steam turbine	Black coal	680	310	400	6.0%	35.9%	0.0902	0.90	$1.18
Hunter Valley Gas Turbine	HVGTS	1/01/2009		Gas turbine	Fuel oil	50	0	0	3.0%	28.0%	0.0697	0.90	$9.50
Liddell	LD01	1/01/2009		Steam turbine	Black coal	525	250	400	5.0%	33.8%	0.0928	0.99	$1.18
Liddell	LD02	1/01/2009		Steam turbine	Black coal	525	250	400	5.0%	33.8%	0.0928	0.99	$1.18
Liddell	LD03	1/01/2009		Steam turbine	Black coal	525	250	440	5.0%	33.8%	0.0928	0.99	$1.18
Liddell	LD04	1/01/2009		Steam turbine	Black coal	525	250	440	5.0%	33.8%	0.0928	0.99	$1.18
Unranquinty	Uran1	15/01/2009		Gas turbine	Natural gas	166	0	0	3.0%	32.0%	0.0513	0.58	$9.98
Unranquinty	Uran2	15/01/2009		Gas turbine	Natural gas	166	0	0	3.0%	32.0%	0.0513	0.58	$9.98
Unranquinty	Uran3	15/01/2009		Gas turbine	Natural gas	166	0	0	3.0%	32.0%	0.0513	0.58	$9.98
Unranquinty	Uran4	15/01/2009		Gas turbine	Natural gas	166	0	0	3.0%	32.0%	0.0513	0.58	$9.98
Smithfield Energy Facility	SITHE01	1/01/2009		Cogeneration	Natural gas	176	140	165	5.0%	41.0%	0.0513	0.45	$2.37
Blowering 1x80MW	BLOWERNG	1/01/2009		Hydro	Hydro	80	12	15	1.0%	100.0%	0	0.00	$5.13
Guthega 2x30MW NSW	GUTHEGANSW1	1/01/2009		Hydro	Hydro	60	0	27	1.0%	100.0%	0	0.00	$7.18
Tumut 1 4x82.4MW NSW	UPPTUMUTNSW1	1/01/2009		Hydro	Hydro	616	0	220	1.0%	100.0%	0	0.00	$7.18
Tumut 3 6x250MW NSW	TUMUT3NSW1	1/01/2009		Hydro	Hydro	1500	0	220	1.0%	100.0%	0	0.00	$11.28
Tallawarra	Tallawarra1	1/01/2009		Gas turbine combined cycle	Natural gas	410	205	320	3.0%	50.0%	0.0513	0.37	$5.03

Data source: ACIL Tasman

Table 29 Initial setting for existing and committed plant, Qld

Generator	DUID	From Date	To Date	Gen Type	Fuel	Unit Size (MW)	MinGen (MW)	Contract cover (MW)	Aux (%)	Thermal efficiency (HHV sent-out, %)	Emission factor (t CO2/GJ)	Emission factor (tCO2/Mwh)	Var O&M (2009 AUD/MWh, sent-out)
Oakey Power Station	OAKEY1	1/01/2009		Gas turbine	Natural gas	141	0	5	3.0%	32.6%	0.0513	0.57	$9.50
Oakey Power Station	OAKEY2	1/01/2009		Gas turbine	Natural gas	141	0	5	3.0%	32.6%	0.0513	0.57	$9.50
Townsville Power Station	YABULU	1/01/2009		Gas turbine combined cycle	Coal seam methane	240	200	200	3.0%	46.0%	0.0513	0.40	$5.03
Braemar	BRAEMAR1	1/01/2009		Gas turbine	Natural gas	168	150	150	2.5%	30.0%	0.0513	0.62	$7.83
Braemar	BRAEMAR2	1/01/2009		Gas turbine	Natural gas	168	0	0	2.5%	30.0%	0.0513	0.62	$7.83
Braemar	BRAEMAR3	1/01/2010		Gas turbine	Natural gas	168	75	150	2.5%	30.0%	0.0513	0.62	$7.83
Callide B Power Station	CALL_B_1	1/01/2009		Steam turbine	Black coal	350	220	260	7.0%	36.1%	0.095	0.95	$1.19
Callide B Power Station	CALL_B_2	1/01/2009		Steam turbine	Black coal	350	220	260	7.0%	36.1%	0.095	0.95	$1.19
Callide Power Plant	CPP_3	1/01/2009		Steam turbine	Black coal	405	200	350	4.8%	36.5%	0.095	0.94	$1.19
Collinsville Power Station	COLNSV_1	1/01/2009		Steam turbine	Black coal	31	16	8	8.0%	27.7%	0.0894	1.16	$1.31
Collinsville Power Station	COLNSV_2	1/01/2009		Steam turbine	Black coal	31	16	8	8.0%	27.7%	0.0894	1.16	$1.31
Collinsville Power Station	COLNSV_3	1/01/2009		Steam turbine	Black coal	31	16	8	8.0%	27.7%	0.0894	1.16	$1.31
Collinsville Power Station	COLNSV_4	1/01/2009		Steam turbine	Black coal	31	16	8	8.0%	27.7%	0.0894	1.16	$1.31
Collinsville Power Station	COLNSV_5	1/01/2009		Steam turbine	Black coal	66	32	16	8.0%	27.7%	0.0894	1.16	$1.31
Kogan Creek	KPP_1	1/01/2009		Steam turbine	Black coal	750	375	622	8.0%	37.5%	0.094	0.90	$1.25
Swanbank B Power Station	SWAN_B_1	1/01/2009		Steam turbine	Black coal	120	45	105	8.0%	30.5%	0.0904	1.07	$1.18
Swanbank B Power Station	SWAN_B_2	1/01/2009		Steam turbine	Black coal	120	45	105	8.0%	30.5%	0.0904	1.07	$1.18
Swanbank B Power Station	SWAN_B_3	1/01/2009		Steam turbine	Black coal	120	45	105	8.0%	30.5%	0.0904	1.07	$1.18
Swanbank B Power Station	SWAN_B_4	1/01/2009		Steam turbine	Black coal	120	45	105	8.0%	30.5%	0.0904	1.07	$1.18
Swanbank E Gas Turbine	SWAN_E	1/01/2009		Gas turbine combined cycle	Coal seam methane	385	180	308	3.0%	47.0%	0.0513	0.39	$5.03
Barcaldine Power Station	BARCALDN	1/01/2009		Gas turbine	Natural gas	55	27	20	3.0%	40.0%	0.0513	0.46	$2.37
Braemar_Two	BRAEMAR_TWO1	1/07/2009		Gas turbine	Natural gas	460	0	0	2.5%	30.0%	0.0513	0.62	$7.83
Callide Power Plant	CPP_4	1/01/2009		Steam turbine	Black coal	405	200	350	4.8%	36.5%	0.095	0.94	$1.19
Millmerran Power Plant	MPP_1	1/01/2009		Steam turbine	Black coal	425.5	100	350	4.5%	37.5%	0.092	0.88	$1.18
Millmerran Power Plant	MPP_2	1/01/2009		Steam turbine	Black coal	425.5	100	350	4.5%	37.5%	0.092	0.88	$1.18
Darling Downs ATR	DDATR1	1/07/2010		Gas turbine combined cycle	Natural gas	630	0	500	6.0%	46.0%	0.0513	0.40	$1.04
Mt Stuart Gas Turbine	MSTUART1	1/01/2009		Gas turbine	Liquid Fuel	146	0	30	3.0%	30.0%	0.0697	0.84	$8.94
Mt Stuart Gas Turbine	MSTUART2	1/01/2009		Gas turbine	Liquid Fuel	146	0	30	3.0%	30.0%	0.0697	0.84	$8.94
Mt Stuart Gas Turbine	MSTUART3	1/07/2009		Gas turbine	Liquid Fuel	126	0	30	3.0%	30.0%	0.0697	0.84	$8.94
Roma Gas Turbine Station	ROMA_7	1/01/2009		Gas turbine	Natural gas	40	0	32	3.0%	30.0%	0.0513	0.62	$9.50
Roma Gas Turbine Station	ROMA_8	1/01/2009		Gas turbine	Natural gas	40	0	32	3.0%	30.0%	0.0513	0.62	$9.50
Condamine Power Station	CONDAMINE1	1/02/2009		Gas turbine	Natural gas	80	0	0	3.0%	33.0%	0.0513	0.56	$9.50
Condamine Power Station	CONDAMINE1	1/08/2009		Gas turbine combined cycle	Natural gas	140	0	90	3.0%	48.0%	0.0513	0.38	$1.04
Yarwun Cogen	YARWUN	1/07/2010		Gas turbine	Natural gas	168	143	143	2.0%	34.0%	0.0513	0.54	$0.00
Barron Gorge	BARRON-1	1/01/2009		Hydro	Hydro	30	15	14	1.0%	100.0%	0	0.00	$11.28
Barron Gorge	BARRON-2	1/01/2009		Hydro	Hydro	30	15	14	1.0%	100.0%	0	0.00	$11.28
Gladstone	GSTONE1	1/01/2009		Steam turbine	Black coal	280	0	0	5.0%	35.2%	0.0921	0.94	$1.18
Gladstone	GSTONE2	1/01/2009		Steam turbine	Black coal	280	110	200	5.0%	35.2%	0.0921	0.94	$1.18
Gladstone	GSTONE3	1/01/2009		Steam turbine	Black coal	280	110	200	5.0%	35.2%	0.0921	0.94	$1.18
Gladstone	GSTONE4	1/01/2009		Steam turbine	Black coal	280	110	200	5.0%	35.2%	0.0921	0.94	$1.18
Gladstone	GSTONE5	1/01/2009		Steam turbine	Black coal	280	110	200	5.0%	35.2%	0.0921	0.94	$1.18
Gladstone	GSTONE6	1/01/2009		Steam turbine	Black coal	280	110	200	5.0%	35.2%	0.0921	0.94	$1.18
Kareeya	KAREEYA1	1/01/2009		Hydro	Hydro	21	8	10	1.0%	100.0%	0	0.00	$6.15
Kareeya	KAREEYA2	1/01/2009		Hydro	Hydro	21	8	10	1.0%	100.0%	0	0.00	$6.15
Kareeya	KAREEYA3	1/01/2009		Hydro	Hydro	18	8	10	1.0%	100.0%	0	0.00	$6.15
Kareeya	KAREEYA4	1/01/2009		Hydro	Hydro	21	8	10	1.0%	100.0%	0	0.00	$6.15
Mackay Gas Turbine	MACKAYGT	1/01/2009		Gas turbine	Fuel oil	34	0	5	3.0%	28.0%	0.0697	0.90	$8.94
Stanwell Power Station	STAN-1	1/01/2009		Steam turbine	Black coal	360	190	260	7.0%	36.4%	0.0904	0.89	$1.18
Stanwell Power Station	STAN-2	1/01/2009		Steam turbine	Black coal	360	190	260	7.0%	36.4%	0.0904	0.89	$1.18
Stanwell Power Station	STAN-3	1/01/2009		Steam turbine	Black coal	360	190	260	7.0%	36.4%	0.0904	0.89	$1.18
Stanwell Power Station	STAN-4	1/01/2009		Steam turbine	Black coal	360	190	260	7.0%	36.4%	0.0904	0.89	$1.18
Tarong North Power Station	TNPS1	1/01/2009		Steam turbine	Black coal	443	250	380	5.0%	39.2%	0.0921	0.85	$1.42
Tarong Power Station	TARONG#1	1/01/2009		Steam turbine	Black coal	350	200	240	8.0%	36.2%	0.0921	0.92	$1.42
Tarong Power Station	TARONG#2	1/01/2009		Steam turbine	Black coal	350	200	240	8.0%	36.2%	0.0921	0.92	$1.42
Tarong Power Station	TARONG#3	1/01/2009		Steam turbine	Black coal	350	200	240	8.0%	36.2%	0.0921	0.92	$1.42
Tarong Power Station	TARONG#4	1/01/2009		Steam turbine	Black coal	350	200	240	8.0%	36.2%	0.0921	0.92	$1.42

Data source: ACIL Tasman

Table 30 **Initial setting for existing and committed plant, SA**

Generator	DUID	From Date	To Date	Gen Type	Fuel	Unit Size (MW)	MinGen (MW)	Contract cover (MW)	Aux (%)	Thermal efficiency (HHV sent-out, %)	Emission factor (t CO2/GJ)	Emission factor (tCO2/Mwh)	Var O&M (2009 AUD/MWh, sent-out)
Torrens Island Power Station A	TORRA1	1/01/2009		Steam turbine	Natural gas	120	2	20	5.0%	27.6%	0.0513	0.67	$2.23
Torrens Island Power Station A	TORRA2	1/01/2009		Steam turbine	Natural gas	120	2	20	5.0%	27.6%	0.0513	0.67	$2.23
Torrens Island Power Station A	TORRA3	1/01/2009		Steam turbine	Natural gas	120	2	20	5.0%	27.6%	0.0513	0.67	$2.23
Torrens Island Power Station A	TORRA4	1/01/2009		Steam turbine	Natural gas	120	2	20	5.0%	27.6%	0.0513	0.67	$2.23
Torrens Island Power Station B	TORRB1	1/01/2009		Steam turbine	Natural gas	200	30	105	5.0%	30.0%	0.0513	0.62	$2.23
Torrens Island Power Station B	TORRB2	1/01/2009		Steam turbine	Natural gas	200	30	105	5.0%	30.0%	0.0513	0.62	$2.23
Torrens Island Power Station B	TORRB3	1/01/2009		Steam turbine	Natural gas	200	30	105	5.0%	30.0%	0.0513	0.62	$2.23
Torrens Island Power Station B	TORRB4	1/01/2009		Steam turbine	Natural gas	200	30	105	5.0%	30.0%	0.0513	0.62	$2.23
Northern Power Station	NPS1	1/01/2009		Steam turbine	Black coal	265	190	240	5.0%	34.9%	0.091	0.94	$1.18
Northern Power Station	NPS2	1/01/2009		Steam turbine	Black coal	265	190	240	5.0%	34.9%	0.091	0.94	$1.18
Playford B Power Station	PLAYB-AG	1/01/2009		Steam turbine	Black coal	240	50	100	8.0%	21.9%	0.091	1.50	$2.97
Angaston	ANGAS1	1/01/2009		Gas turbine	Distillate	30	0	0	2.5%	26.0%	0.0679	0.94	$9.50
Angaston	ANGAS2	1/01/2009		Gas turbine	Distillate	20	0	0	2.5%	26.0%	0.0679	0.94	$9.50
Dry Creek Gas Turbine Station	DRYCGT1	1/01/2009		Gas turbine	Natural gas	52	0	0	3.0%	26.0%	0.0513	0.71	$9.50
Dry Creek Gas Turbine Station	DRYCGT2	1/01/2009		Gas turbine	Natural gas	52	0	0	3.0%	26.0%	0.0513	0.71	$9.50
Dry Creek Gas Turbine Station	DRYCGT3	1/01/2009		Gas turbine	Natural gas	52	0	0	3.0%	26.0%	0.0513	0.71	$9.50
Mintaro Gas Turbine Station	MINTARO	1/01/2009		Gas turbine	Natural gas	90	0	0	3.0%	28.0%	0.0513	0.66	$9.50
Pelican Point Power Station	PPCCGT	1/01/2009		Gas turbine combined cycle	Natural gas	485	370	440	2.0%	48.0%	0.0513	0.38	$5.03
Port Lincoln Gas Turbine	POR01	1/01/2009		Gas turbine	Distillate	50	0	0	8.0%	26.0%	0.0679	0.94	$9.50
Snuggery Power Station	SNUG1	1/01/2009		Gas turbine	Distillate	63	0	20	3.0%	26.0%	0.0679	0.94	$9.50
Ladbroke Grove Power Station	LADBROK1	1/01/2009		Gas turbine	Natural gas	40	0	35	3.0%	30.0%	0.0513	0.62	$3.55
Ladbroke Grove Power Station	LADBROK2	1/01/2009		Gas turbine	Natural gas	40	0	35	3.0%	30.0%	0.0513	0.62	$3.55
Osborne Power Station	OSB-AG	1/01/2009		Cogeneration	Natural gas	180	125	132	5.0%	42.0%	0.0513	0.44	$5.03
Quarantine Power Station	QPS1	1/01/2009		Gas turbine	Natural gas	24	0	5	5.0%	32.0%	0.0513	0.58	$9.50
Quarantine Power Station	QPS2	1/01/2009		Gas turbine	Natural gas	24	0	5	5.0%	32.0%	0.0513	0.58	$9.50
Quarantine Power Station	QPS3	1/01/2009		Gas turbine	Natural gas	24	0	5	5.0%	32.0%	0.0513	0.58	$9.50
Quarantine Power Station	QPS4	1/01/2009		Gas turbine	Natural gas	24	0	5	5.0%	32.0%	0.0513	0.58	$9.50
Quarantine Power Station	QPS5	1/01/2009		Gas turbine	Natural gas	120	0	30	5.0%	32.0%	0.0513	0.58	$9.50
Hallett Power Station	AGLHAL	1/01/2009		Gas turbine	Natural gas	180	0	10	2.5%	24.0%	0.0513	0.77	$9.50

Data source: ACIL Tasman

Table 31 **Initial setting for existing and committed plant, Tas**

Generator	DUID	From Date	To Date	Gen Type	Fuel	Unit Size (MW)	MinGen (MW)	Contract cover (MW)	Aux (%)	Thermal efficiency (HHV sent-out, %)	Emission factor (t CO2/GJ)	Emission factor (tCO2/Mwh)	Var O&M (2009 AUD/MWh, sent-out)
Bell Bay	BELLBAY1	1/01/2009		Steam turbine	Natural gas	120	20	60	5.0%	32.0%	0.0513	0.58	$7.83
Bell Bay	BELLBAY2	1/01/2009		Steam turbine	Natural gas	120	20	60	5.0%	32.0%	0.0513	0.58	$7.83
Bell Bay Three	BELLBAYTHREE1	1/01/2009	30/06/2009	Gas turbine	Natural gas	35	0	0	2.5%	29.0%	0.0513	0.64	$7.83
Bell Bay Three	BELLBAYTHREE1	1/07/2009		Gas turbine	Natural gas	60	0	0	2.5%	29.0%	0.0513	0.64	$7.83
Bell Bay Three	BELLBAYTHREE2	1/01/2009	30/06/2009	Gas turbine	Natural gas	35	0	0	2.5%	29.0%	0.0513	0.64	$7.83
Bell Bay Three	BELLBAYTHREE2	1/07/2009		Gas turbine	Natural gas	60	0	0	2.5%	29.0%	0.0513	0.64	$7.83
Bell Bay Three	BELLBAYTHREE3	1/01/2009	30/06/2009	Gas turbine	Natural gas	35	0	0	2.5%	29.0%	0.0513	0.64	$7.83
Bell Bay Three	BELLBAYTHREE3	1/07/2009		Gas turbine	Natural gas	60	0	0	2.5%	29.0%	0.0513	0.64	$7.83
Tamar Valley Power Station CCGT1	TVPSCCGT1U1	1/07/2009		Gas turbine combined cycle	Natural gas	200	100	160	3.0%	48.0%	0.0513	0.38	$5.03
Bastyan	BASTYAN1	1/01/2009		Hydro	Hydro	79.9	14	14	5.0%	100.0%	0	0.00	$6.15
Cethana	CETHANA1	1/01/2009		Hydro	Hydro	85	40	40	0.5%	100.0%	0	0.00	$6.15
Devils Gate	DEVILS1	1/01/2009		Hydro	Hydro	60	32	32	0.5%	100.0%	0	0.00	$6.15
Fisher	FISHER1	1/01/2009		Hydro	Hydro	43.2	12	12	0.5%	100.0%	0	0.00	$5.13
Gordon	GORDON1	1/01/2009		Hydro	Hydro	432	0	5	0.5%	100.0%	0	0.00	$5.13
John Butters	BUTTERS1	1/01/2009		Hydro	Hydro	144	0	0	0.5%	100.0%	0	0.00	$6.15
Lake Echo	ECHO1	1/01/2009		Hydro	Hydro	32.4	0	0	0.5%	100.0%	0	0.00	$6.15
Lemonthyme_Wilmot	LEMONTHYME1	1/01/2009		Hydro	Hydro	51	5	5	0.5%	100.0%	0	0.00	$6.15
Lemonthyme_Wilmot	WILMOT1	1/01/2009		Hydro	Hydro	30.6	10	10	0.5%	100.0%	0	0.00	$6.15
Liapootah_Wayatinah_Catagunya	CATAGUNYA1	1/01/2009		Hydro	Hydro	48	8	8	0.5%	100.0%	0	0.00	$6.15
Liapootah_Wayatinah_Catagunya	LIAPOOTAH1	1/01/2009		Hydro	Hydro	83.7	14	110	0.5%	100.0%	0	0.00	$6.15
Liapootah_Wayatinah_Catagunya	WAYATINAH1	1/01/2009		Hydro	Hydro	38.3	11	11	0.5%	100.0%	0	0.00	$6.15
Mackintosh	MAKCINTOSH1	1/01/2009		Hydro	Hydro	79.9	20	20	0.5%	100.0%	0	0.00	$6.15
Meadowbank	MEADOWBANK1	1/01/2009		Hydro	Hydro	40	24	24	0.5%	100.0%	0	0.00	$6.15
Poatina	POATINA1	1/01/2009		Hydro	Hydro	300	0	0	0.5%	100.0%	0	0.00	$6.15
Reece	REECE1	1/01/2009		Hydro	Hydro	231.2	93	380	0.5%	100.0%	0	0.00	$6.15
Tarraleah	TARRALEAH	1/01/2009		Hydro	Hydro	90	36	36	0.5%	100.0%	0	0.00	$6.15
Trevallyn	TREVALLYN	1/01/2009		Hydro	Hydro	80	38	42	0.5%	100.0%	0	0.00	$6.15
Tribute	TRIBUTE1	1/01/2009		Hydro	Hydro	82.8	28	28	0.5%	100.0%	0	0.00	$6.15
Tungatinah	TUNGATINAH1	1/01/2009		Hydro	Hydro	125	20	20	0.5%	100.0%	0	0.00	$6.15

Data source: ACIL Tasman

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

Generator	DUID	From Date	To Date	Gen Type	Fuel	Unit Size (MW)	MinGen (MW)	Contract cover (MW)	Aux (%)	Thermal efficiency (HHV sent-out, %)	Emission factor (t CO2/GJ)	Emission factor (tCO2/Mwh)	Var O&M (2009 AUD/MWh, sent-out)
Bogong	BOGONG1	1/10/2009		Hydro	Hydro	140	8	40	1.0%	100.0%	0	0.00	$7.18
Dartmouth Power Station	DARTM1	1/01/2009		Hydro	Hydro	158	0	0	1.0%	100.0%	0	0.00	$6.15
Eildon Power Station	EILDON1	1/01/2009		Hydro	Hydro	60	0	20	1.0%	100.0%	0	0.00	$9.23
Eildon Power Station	EILDON2	1/01/2009		Hydro	Hydro	60	0	20	1.0%	100.0%	0	0.00	$9.23
McKay Power Station	MCKAY1	1/01/2009		Hydro	Hydro	100	0	15	1.0%	100.0%	0	0.00	$7.18
McKay Power Station	MCKAY2	1/01/2009		Hydro	Hydro	50	0	5	1.0%	100.0%	0	0.00	$7.18
McKay Power Station	MCKAY2	1/10/2009		Hydro	Hydro	60	0	5	1.0%	100.0%	0	0.00	$7.18
Somerton Power Station	AGLSOM	1/01/2009		Gas turbine	Natural gas	160	0	5	2.5%	24.0%	0.0513	0.77	$9.50
West Kiewa Power Station	WKIEWA1	1/01/2009		Hydro	Hydro	31	2	8	1.0%	100.0%	0	0.00	$7.18
West Kiewa Power Station	WKIEWA2	1/01/2009		Hydro	Hydro	31	2	8	1.0%	100.0%	0	0.00	$7.18
Bairnsdale Power Station	BDL01	1/01/2009		Gas turbine	Natural gas	46	10	20	3.0%	34.0%	0.0513	0.54	$2.23
Bairnsdale Power Station	BDL02	1/01/2009		Gas turbine	Natural gas	46	10	20	3.0%	34.0%	0.0513	0.54	$2.23
Hume Power Station Vic	HUMEV	1/01/2009		Hydro	Hydro	29	12	0	1.0%	100.0%	0	0.00	$6.15
Energy Brix Complex	MOR1	1/01/2009		Steam turbine	Brown coal	90	65	65	15.0%	24.0%	0.099	1.49	$2.18
Energy Brix Complex	MOR2	1/01/2009		Steam turbine	Brown coal	30	14	14	15.0%	24.0%	0.099	1.49	$2.18
Energy Brix Complex	MOR3	1/01/2009		Steam turbine	Brown coal	75	37	37	15.0%	24.0%	0.099	1.49	$2.18
Hazelwood Power Station	HWPS1	1/01/2009		Steam turbine	Brown coal	205	130	180	10.0%	22.0%	0.093	1.52	$1.18
Hazelwood Power Station	HWPS2	1/01/2009		Steam turbine	Brown coal	205	130	180	10.0%	22.0%	0.093	1.52	$1.18
Hazelwood Power Station	HWPS3	1/01/2009		Steam turbine	Brown coal	205	130	180	10.0%	22.0%	0.093	1.52	$1.18
Hazelwood Power Station	HWPS4	1/01/2009		Steam turbine	Brown coal	205	130	180	10.0%	22.0%	0.093	1.52	$1.18
Hazelwood Power Station	HWPS5	1/01/2009		Steam turbine	Brown coal	205	130	180	10.0%	22.0%	0.093	1.52	$1.18
Hazelwood Power Station	HWPS6	1/01/2009		Steam turbine	Brown coal	205	130	180	10.0%	22.0%	0.093	1.52	$1.18
Hazelwood Power Station	HWPS7	1/01/2009		Steam turbine	Brown coal	205	130	180	10.0%	22.0%	0.093	1.52	$1.18
Hazelwood Power Station	HWPS8	1/01/2009		Steam turbine	Brown coal	205	130	180	10.0%	22.0%	0.093	1.52	$1.18
Loy Yang B Power Station	LOYYB1	1/01/2009		Steam turbine	Brown coal	525	200	450	7.5%	26.6%	0.0915	1.24	$1.18
Loy Yang B Power Station	LOYYB2	1/01/2009		Steam turbine	Brown coal	525	200	450	7.5%	26.6%	0.0915	1.24	$1.18
Loy Yang A Power Station	LYA1	1/01/2009		Steam turbine	Brown coal	560	400	485	9.0%	27.2%	0.0915	1.21	$1.18
Loy Yang A Power Station	LYA2	1/01/2009		Steam turbine	Brown coal	520	400	485	9.0%	27.2%	0.0915	1.21	$1.18
Loy Yang A Power Station	LYA3	1/01/2009		Steam turbine	Brown coal	560	400	485	9.0%	27.2%	0.0915	1.21	$1.18
Loy Yang A Power Station	LYA4	1/01/2009		Steam turbine	Brown coal	540	400	485	9.0%	27.2%	0.0915	1.21	$1.18
Anglesea Power Station	APS	1/01/2009		Steam turbine	Brown coal	160	150	160	10.0%	27.2%	0.091	1.20	$1.18
Laverton North Power Station	LAVNORTH	1/01/2009		Gas turbine	Natural gas	312	0	0	2.5%	30.4%	0.0513	0.61	$7.83
Murray 1 10x95MW Vic	MURRAYVIC1	1/01/2009		Hydro	Hydro	1500	120	440	1.0%	100.0%	0	0.00	$6.15
Snowy Vic	SNOWYPVIC1	1/01/2009		Hydro	Hydro	1	0	0	1.0%	100.0%	0	0.00	$0.00
Valley Power Peaking Facility	VPGS1	1/01/2009		Gas turbine	Natural gas	50	0	5	3.0%	24.0%	0.0513	0.77	$9.50
Valley Power Peaking Facility	VPGS2	1/01/2009		Gas turbine	Natural gas	50	0	5	3.0%	24.0%	0.0513	0.77	$9.50
Valley Power Peaking Facility	VPGS3	1/01/2009		Gas turbine	Natural gas	50	0	5	3.0%	24.0%	0.0513	0.77	$9.50
Valley Power Peaking Facility	VPGS4	1/01/2009		Gas turbine	Natural gas	50	0	5	3.0%	24.0%	0.0513	0.77	$9.50
Valley Power Peaking Facility	VPGS5	1/01/2009		Gas turbine	Natural gas	50	0	5	3.0%	24.0%	0.0513	0.77	$9.50
Valley Power Peaking Facility	VPGS6	1/01/2009		Gas turbine	Natural gas	50	0	5	3.0%	24.0%	0.0513	0.77	$9.50
Jeeralang A Power Station	JLA01	1/01/2009		Gas turbine	Natural gas	57	0	20	3.0%	22.9%	0.0513	0.81	$8.94
Jeeralang A Power Station	JLA02	1/01/2009		Gas turbine	Natural gas	57	0	20	3.0%	22.9%	0.0513	0.81	$8.94
Jeeralang A Power Station	JLA03	1/01/2009		Gas turbine	Natural gas	57	0	20	3.0%	22.9%	0.0513	0.81	$8.94
Jeeralang A Power Station	JLA04	1/01/2009		Gas turbine	Natural gas	57	0	20	3.0%	22.9%	0.0513	0.81	$8.94
Jeeralang B Power Station	JLB01	1/01/2009		Gas turbine	Natural gas	85	0	40	3.0%	22.9%	0.0513	0.81	$8.94
Jeeralang B Power Station	JLB02	1/01/2009		Gas turbine	Natural gas	85	0	40	3.0%	22.9%	0.0513	0.81	$8.94
Jeeralang B Power Station	JLB03	1/01/2009		Gas turbine	Natural gas	85	0	40	3.0%	22.9%	0.0513	0.81	$8.94
Newport Power Station	NPS	1/01/2009		Steam turbine	Natural gas	500	0	100	5.0%	33.3%	0.0513	0.55	$2.23
Yallourn W Power Station	YWPS1	1/01/2009		Steam turbine	Brown coal	360	220	303	8.9%	23.5%	0.0925	1.42	$1.18
Yallourn W Power Station	YWPS2	1/01/2009		Steam turbine	Brown coal	360	220	303	8.9%	23.5%	0.0925	1.42	$1.18
Yallourn W Power Station	YWPS3	1/01/2009		Steam turbine	Brown coal	380	220	323	8.9%	23.5%	0.0925	1.42	$1.18
Yallourn W Power Station	YWPS4	1/01/2009		Steam turbine	Brown coal	380	220	323	8.9%	23.5%	0.0925	1.42	$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.

In Queensland, it is assumed that drought conditions which have lowered the generation from Tarong Power Station and Swanbank B during 2007/08 have subsided, allowing the stations to return to full service by 2009. The modelling shows a decrease in Swanbank B's dispatch when Kogan Creek was commissioned in November 2007 - due to Swanbank B being the most expensive coal fired plant in the CS portfolio.

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	
			New South Wales		
TRUenergy	Tallawarra	CCGT/Gas	410	Jul 2008	
BBP	Uranquinty	GT/Gas	664	From Feb 2009	
Delta	Colongra	GT/Gas	664	Dec 2009	
Delta	Mt Piper U1-U2	Black coal	+90MW per unit	Assumed not to proceed	
Eraring	Eraring	Black coal	+60MW per unit	2010	
			South Australia (note wind farms must be scheduled generators in SA)		
Origin Energy	Quarantine	OCGT	+120	Dec 2008	
AGL Energy	Hallett wind farm	Wind	95	April 2008	
NP Power	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	
IPM	Snuggery	OCGT	42	No longer being retired	
			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	
Origin Energy	Darling Downs	CCGT	630	March 2010	
Origin Energy	Mt Stuart	OCGT	126	October 2009	
Rio Tinto	Yarwun	CCGT/Cogen	168	July 2010	
			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%.

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 two 4 million tonne per annum LNG facilities constructed in 2014 and 2018. This has a demand for gas feed of 220 PJ/a commencing in 2014 and increasing to 440 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 ROM netback price whichever is the higher. For power stations that are not mine mouth, we include the efficient cost of transportation - either 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 cash costs for mining the coal.

Table 34 details the estimated marginal costs for coal at each power station. The marginal costs for coal are based on the cost of electricity required to produce the marginal tonne and the royalty charges.

Table 34 **Estimated coal costs for Victorian generators in 2009/10**

Power Station / Mine	Total Cash Cost $/t	Variable Cost $/t	Energy Content GJ/t	Variable Cost $/GJ
Yallourn/Yallourn	$3.24	$0.62	6.8	$0.10
Loy Yang A - directly form Loy Yang mine	$3.00	$0.65	8.2	$0.08
Loy Yang B - purchased from Loy Yang mine	$3.00	$3.00	8.2	$0.37
Hazelwood/Morwell	$4.19	$0.60	7.0	$0.08
Anglesea/Anglesea	$5.99	$5.99	15.0	$0.40
Energy Brix/Morwell	$4.19	$4.19	7.0	$0.60

Data source: ACIL Tasman analysis

The variable cost of coal as calculated in Table 34 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 $1.40/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 35 **Assumed nominal fuel costs ($/GJ) by station by year**

Region	Generator	Fuel	2010-11
NSW1	Bayswater	Black coal	$1.29
NSW1	Colongra	Natural gas	$7.25
NSW1	Eraring Power Station	Black coal	$1.78
NSW1	Hunter Valley Gas Turbine	Fuel oil	$31.10
NSW1	Liddell	Black coal	$1.29
NSW1	Mt Piper Power Station	Black coal	$1.84
NSW1	Munmorah Power Station	Black coal	$1.80
NSW1	Redbank Power Station	Black coal	$1.04
NSW1	Smithfield Energy Facility	Natural gas	$4.33
NSW1	Tallawarra	Natural gas	$3.94
NSW1	Uranquinty	Natural gas	$6.50
NSW1	Vales Point B Power Station	Black coal	$1.80
NSW1	Wallerawang C Power Station	Black coal	$1.84
QLD1	Barcaldine Power Station	Natural gas	$6.89
QLD1	Braemar	Natural gas	$4.74
QLD1	Braemar_Two	Natural gas	$2.99
QLD1	Callide B Power Station	Black coal	$1.36
QLD1	Callide Power Plant	Black coal	$1.36
QLD1	Collinsville Power Station	Black coal	$2.17
QLD1	Condamine Power Station	Natural gas	$0.98
QLD1	Darling Downs	Natural gas	$3.54
QLD1	Gladstone	Black coal	$1.62
QLD1	Kogan Creek	Black coal	$0.78
QLD1	Mackay Gas Turbine	Fuel oil	$31.10
QLD1	Millmerran Power Plant	Black coal	$0.88
QLD1	Mt Stuart Gas Turbine	Liquid Fuel	$31.10
QLD1	Oakey Power Station	Natural gas	$4.38
QLD1	Roma Gas Turbine Station	Natural gas	$4.74
QLD1	Stanwell Power Station	Black coal	$1.44
QLD1	Swanbank B Power Station	Black coal	$2.27
QLD1	Swanbank E Gas Turbine	Coal seam methane	$3.58
QLD1	Tarong North Power Station	Black coal	$1.04
QLD1	Tarong Power Station	Black coal	$1.04
QLD1	Townsville Power Station	Coal seam methane	$4.19
QLD1	Yarwun Cogen	Natural gas	$3.69
SA1	Angaston	Distillate	$31.10
SA1	Dry Creek Gas Turbine Station	Natural gas	$4.88
SA1	Hallett Power Station	Natural gas	$6.85
SA1	Ladbroke Grove Power Station	Natural gas	$5.23
SA1	Mintaro Gas Turbine Station	Natural gas	$6.85
SA1	Northern Power Station	Black coal	$1.58
SA1	Osborne Power Station	Natural gas	$4.28
SA1	Pelican Point Power Station	Natural gas	$4.11
SA1	Playford B Power Station	Black coal	$1.58
SA1	Port Lincoln Gas Turbine	Distillate	$31.10
SA1	Quarantine Power Station	Natural gas	$6.20
SA1	Snuggery Power Station	Distillate	$31.10
SA1	Torrens Island Power Station A	Natural gas	$4.18
SA1	Torrens Island Power Station B	Natural gas	$4.18
TAS1	Bell Bay	Natural gas	$5.72
TAS1	Bell Bay Three	Natural gas	$5.72
VIC1	Anglesea Power Station	Brown coal	$0.41
VIC1	Bairnsdale Power Station	Natural gas	$4.45
VIC1	Energy Brix Complex	Brown coal	$0.61
VIC1	Hazelwood Power Station	Brown coal	$0.09
VIC1	Jeeralang A Power Station	Natural gas	$4.02
VIC1	Jeeralang B Power Station	Natural gas	$4.02
VIC1	Laverton North Power Station	Natural gas	$4.26
VIC1	Loy Yang A Power Station	Brown coal	$0.09
VIC1	Loy Yang B Power Station	Brown coal	$0.38
VIC1	Mortlake OCGT	Natural gas	$5.80
VIC1	Newport Power Station	Natural gas	$4.23
VIC1	Somerton Power Station	Natural gas	$4.26
VIC1	Valley Power Peaking Facility	Natural gas	$4.01
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.1.1 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.1.2 Marginal loss factors

The marginal loss factors (MLFs) assumed in the scenarios are taken directly from the latest NEMMCO report – "List of Regional Boundaries and Marginal Loss Factors for the 2008/09 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.1.3 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 36 summarises the nominal SRMC assumed for each station.

Table 36 **Station nominal SRMC ($/MWh) for existing or committed plant**

Region	Station name	Fuel	2010-11
NSW1	Bayswater	Black coal	$17.33
NSW1	Colongra	Natural gas	$91.23
NSW1	Eraring Power Station	Black coal	$19.30
NSW1	Hunter Valley Gas Turbine	Fuel oil	$409.66
NSW1	Liddell	Black coal	$18.75
NSW1	Mt Piper Power Station	Black coal	$19.30
NSW1	Munmorah Power Station	Black coal	$23.26
NSW1	Redbank Power Station	Black coal	$14.06
NSW1	Smithfield Energy Facility	Natural gas	$40.52
NSW1	Tallawarra	Natural gas	$29.78
NSW1	Unranquinty	Natural gas	$82.77
NSW1	Vales Point B Power Station	Black coal	$19.50
NSW1	Wallerawang C Power Station	Black coal	$21.42
QLD1	Barcaldine Power Station	Natural gas	$58.78
QLD1	Braemar	Natural gas	$59.09
QLD1	Braemar_Two	Natural gas	$37.24
QLD1	Callide B Power Station	Black coal	$14.83
QLD1	Callide Power Plant	Black coal	$14.95
QLD1	Collinsville Power Station	Black coal	$29.58
QLD1	Condamine Power Station	Natural gas	$2.52
QLD1	Darling Downs	Natural gas	$14.57
QLD1	Gladstone	Black coal	$17.77
QLD1	Kogan Creek	Black coal	$8.74
QLD1	Mackay Gas Turbine	Fuel oil	$409.08
QLD1	Millmerran Power Plant	Black coal	$9.66
QLD1	Mt Stuart Gas Turbine	Liquid Fuel	$382.42
QLD1	Oakey Power Station	Natural gas	$52.54
QLD1	Roma Gas Turbine Station	Natural gas	$60.86
QLD1	Stanwell Power Station	Black coal	$15.51
QLD1	Swanbank B Power Station	Black coal	$28.02
QLD1	Swanbank E Gas Turbine	Coal seam me	$24.55
QLD1	Tarong North Power Station	Black coal	$10.73
QLD1	Tarong Power Station	Black coal	$11.82
QLD1	Townsville Power Station	Coal seam me	$30.03
QLD1	Yarwun Cogen	Natural gas	$19.77
SA1	Angaston	Distillate	$440.41
SA1	Dry Creek Gas Turbine Station	Natural gas	$77.39
SA1	Hallett Power Station	Natural gas	$112.68
SA1	Ladbroke Grove Power Station	Natural gas	$66.45
SA1	Mintaro Gas Turbine Station	Natural gas	$97.99
SA1	Northern Power Station	Black coal	$17.51
SA1	Osborne Power Station	Natural gas	$41.89
SA1	Pelican Point Power Station	Natural gas	$33.98
SA1	Playford B Power Station	Black coal	$29.04
SA1	Port Lincoln Gas Turbine	Distillate	$440.41
SA1	Quarantine Power Station	Natural gas	$78.98
SA1	Snuggery Power Station	Distillate	$440.41
SA1	Torrens Island Power Station A	Natural gas	$56.83
SA1	Torrens Island Power Station B	Natural gas	$34.99
TAS1	Bell Bay	Natural gas	$0.00
TAS1	Bell Bay Three	Natural gas	$78.32
VIC1	Anglesea Power Station	Brown coal	$6.59
VIC1	Bairnsdale Power Station	Natural gas	$49.41
VIC1	Energy Brix Complex	Brown coal	$11.48
VIC1	Hazelwood Power Station	Brown coal	$2.63
VIC1	Jeeralang A Power Station	Natural gas	$72.45
VIC1	Jeeralang B Power Station	Natural gas	$72.45
VIC1	Laverton North Power Station	Natural gas	$57.57
VIC1	Loy Yang A Power Station	Brown coal	$2.36
VIC1	Loy Yang B Power Station	Brown coal	$6.38
VIC1	Mortlake OCGT	Natural gas	$37.39
VIC1	Newport Power Station	Natural gas	$48.01
VIC1	Somerton Power Station	Natural gas	$73.83
VIC1	Valley Power Peaking Facility	Natural gas	$70.04
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:

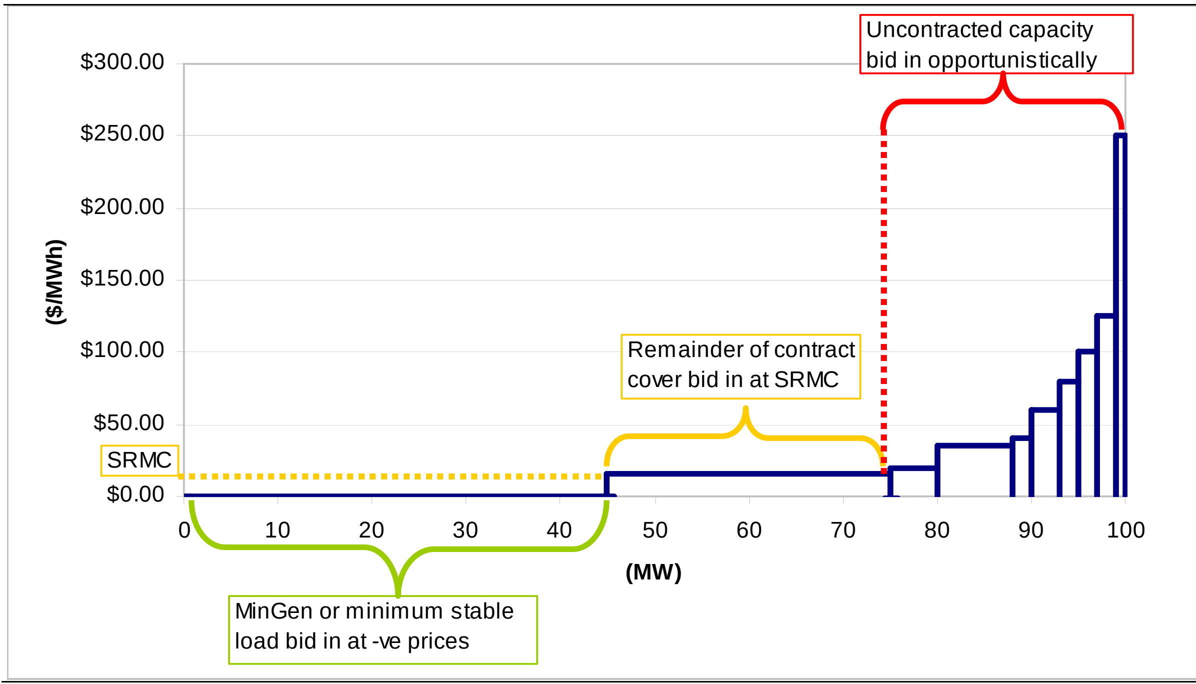
- the assumed level of MinGen, which is offered between -$1000/MWh and $0/MWh; and
- the assumed level of contract cover, which is offered at the SRMC of the plant.

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 5 **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)[13]. 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[14]), 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

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

[14] '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 37 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 37 **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*