The calculation of energy costs in the BRCI for 2010-11

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

Prepared for the Queensland Competition Authority

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ACIL Tasman

Economics Policy Strategy

Reliance and Disclaimer

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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 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.

ACIL Tasman also provided a forecast of the NEM load for Queensland for 2009 to be used as the denominator in the in the calculation of the BRCI.

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 vs the QCA and Origin Energy vs QCA in the Supreme Court of Queensland (2009) 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 Australian dollar exchange rate.

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.

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[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 2010-11 cost of energy components of the BRCI calculation compared to the results for the same components calculated for the 2009-10 BRCI by CRA.

Table 1 **Summary of results for the energy cost components of the 2010-11 BRCI compared to the 2009-10 CRA results**

	(CRA) 2009-10	(ACIL Tasman) 2010-11
NEM load MWh	36,850,890	37,483,145
Energy costs		
LRMC	$53.28	$58.51
Energy purchase costs (EPC)	$57.70	$58.72
Energy - based on 50% weighting	$55.49	$58.62
Renewable Energy Target	$2.43	$3.02
Queensland Gas Scheme	$2.56	$2.80
NEM fees	$0.33	$0.37
Ancillary services	$0.40	$0.45
Total energy costs ($MWh)	**$61.21**	**$65.26**
$ millions	**$2,255,642,977**	**$2,446,051,600**

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.

However, the Supreme Court ruling of 24 April 2009 determined that the LRMC should be estimated for "*the aggregate state load which is connected to the national grid*" (paragraph 70 of the decision in AGL Energy Ltd v Queensland Competition Authority & Anor; Origin Energy Retail Ltd v Queensland Competition Authority & Anor [2009] QSC 90).

The least cost modelling approach is similar in principle and application to that used in previous years and we believe complies with 106(a) above. The model produces results consistent with 106(b) and (c), but we have adopted paragraph 70 of the Supreme Court ruling and therefore have used the aggregate state load (that is, the load including customers directly connected to the transmission system as well as to the supply network) in calculating the LRMC. Finally, the approach taken, while taking into account the effects of schemes such as RECs and GECs on energy costs, we believe 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.

- Developing recent and reliable forecasts of fuel, capital and O & M costs for the range of power stations in use in the NEM,
- Taking into account state and Commonwealth programs that add or subtract to energy costs, such as the RET and GEC schemes,
- Using 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 optimising model, PowerMark LT, to calculate the LRMC for the Queensland region of the Australian NEM.

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[3] 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.

[3] The centroid of a cluster is the average point in the multidimensional space defined by the dimensions (in this case the dimensions are the regions of the NEM and the observations are the demands). In this method, the distance between each pair of demand clusters is determined as the difference between the centroids. The weighting is used to take into account differences in cluster sizes (i.e., the number of observations contained in them) - which is the preferred approach when there are suspected to be considerable differences in cluster sizes. The pair of clusters which are closest are joined together as one cluster. The process commences with each of the 17,520 demand sets in individual clusters, the closest pair of clusters is then joined to form a new cluster, which results in 17,519 clusters and the process is then repeated until the target number of clusters is achieved.

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.

2.2.1 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.

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) and costs relating to IDC are implicitly included within the new entrant model.

An international database of published capital costs for new entrant power plant has also be 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.

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 (AUD/kW, 2010-11 $)**

	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19
Concept Economics Oct 2008										
Black Coal	$2,264	$2,258	$2,250	$2,242	$2,233	$2,225	$2,217	$2,209	$2,201	$2,193
Brown Coal	$2,485	$2,477	$2,468	$2,458	$2,449	$2,438	$2,429	$2,420	$2,411	$2,401
CCGT	$1,232	$1,229	$1,224	$1,219	$1,215	$1,210	$1,204	$1,200	$1,195	$1,191
OCGT	$925	$921	$917	$914	$910	$907	$903	$900	$896	$892
Wind	$2,381	$2,348	$2,312	$2,278	$2,243	$2,209	$2,175	$2,142	$2,109	$2,074
Hydro	$2,773	$2,773	$2,773	$2,773	$2,773	$2,773	$2,773	$2,773	$2,773	$2,773
Geothermal	$5,148	$5,132	$5,110	$5,088	$5,067	$5,044	$5,023	$5,002	$4,980	$4,959
Biomass	$5,131	$5,117	$5,097	$5,077	$5,057	$5,037	$5,017	$4,998	$4,977	$4,959
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 (AUD/kW, 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 (AUD/kW, 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.[4]

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

[4] 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 output of a power station to the output of the power station operating at full capacity over one year. The reasons why output is lower than the potential include maintenance outages (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).

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.

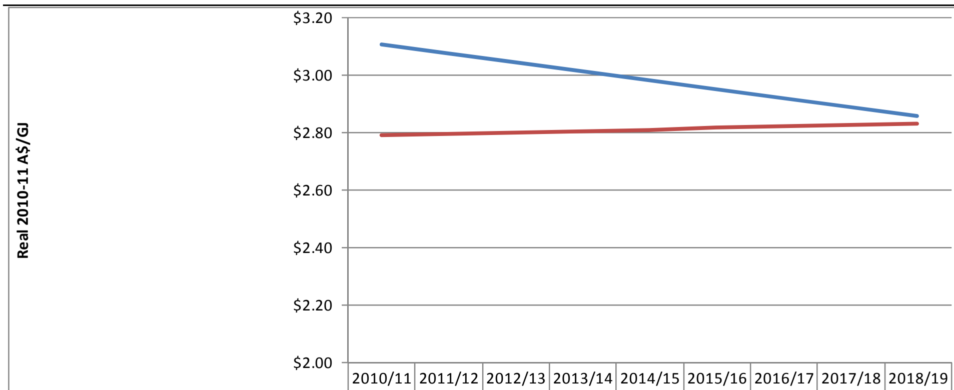
Coal

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, that 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 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 FOB export prices for thermal coal is shown in Figure 1.

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: ACIL Tasman analysis

In arriving at the black coal costs in NSW and Queensland we have averaged the coal prices into the existing stations. This has been done on the assumption that the existing domestic coal supply sources will be available to the new build coal stations in the calculation of 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: AXCIL 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 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.[5]

[5] 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.

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 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 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.

There are a number different expressions for post-tax WACC, the most common ones include:[6]

- Vanilla
- Monkhouse
- Officer.

The Officer formula is the most complex of these owing to the fact that it incorporates all tax effects in the WACC calculation itself and is applied to simple post-tax cash flows. The Officer WACC is the most widely cited as the target post-tax WACC because this definition of WACC 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 which 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 we undertake with the LRMC financial model.

The post-tax real Officer WACC within the new entrant model is applied to un-geared cash flows that do not include the effects of the interest tax shield or dividend imputation credits.

The post-tax nominal Officer WACC as in the LRMC modelling is expressed as:

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

Where:

- E is the total market value of equity, 0.4
- D is the total market value of debt, 0.6

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

- 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 = the relevant inflation rate, assumed at 2.5%, giving a post-tax real WACC of 6.81%.

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.

Table 12 **WACC parameters**

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

Interest during construction

It is worth noting that the model applies the discounting factor (the WACC in this case) from year zero, which is the commencement of construction. This means that negative cash flows during the construction period are increased by the weighted average of the industry return on equity and interest rate. Interest incurred during the construction period is being taken into account through this mechanism.

In effect all costs during this period, including the return on capital and interest costs, are being capitalised as they contribute to accumulated negative cash flow against which future positive cash flows will be offset.

For tax purposes, interest during construction is carried forward as a tax deduction from year zero until the project provides enough taxable income for it to be deducted.

2.3.8 The Average Loss Factor (ALF)

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

Queensland (and other) regions and the appropriate transmission loss factor is the average for the Queensland region, the ALF.

The ALF has been calculated in a similar way to previous years. Powerlink's Annual Planning Report, 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 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 regional reference prices RRPs for a given year are therefore the LRMC in each region of the market as they are the prices that support the least cost combination of new plant.

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

The long term model draws on the individual life cycle costs of the available generation technologies from the individual new entrant financial models done 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 LRMC. 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 pool prices 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 very likely over the coming years, the precise form of such a scheme is still unknown. The date of introduction and the price of emissions permits are currently 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

The Electricity Regulation requires the LRMC to be calculated to meet the demand profile formed over each half-hour for the previous calendar year. Therefore, the LRMC for 2010-11 is to be calculated on the basis of the generation required to meet demand in calendar year 2009. For the Draft Decision, the actual load data for the 2009 calendar year was only available for the period from 1 January to 30 September 2009. Therefore, the demand duration curve for the model has been built from actual half-hourly demands for year 1 October 2008 to 30 September 2009 from the AEMO website.

The complete set of actual 2009 calendar year load data will become available in time for use in the Final Decision.

These demands are on an as generated basis and include electricity delivered from the transmission system to the distribution system <u>as well as demand of end-users directly connected to the transmission system</u> (consistent with the Supreme Court ruling, as mentioned in Section 2.1).

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 17,520.

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). We have used the medium economic growth series and 50%POE peak demand forecast from the 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 Report.

Using an incomplete set of calendar year loads

We note that in BRCI draft decisions of previous years, in the absence of a complete set of loads for the required calendar year (in this case, 2009), CRA has estimated the complete set of loads using a form of simulation process. We have not used this approach – instead for the draft decision we have taken the much simpler approach of using the loads for October to December 2008 to represent the loads for October to December 2009. Our reasons for this are as follows:

- For the final decision the complete set of actual loads will be available and we will use these loads for calculation of the LRMC;
- While it may be argued that our approach is not accurately representing the shape of the 2009 load profile there are two important steps in the LRMC calculation process which will change the shape of the profile (whether it be a complete or incomplete profile):
  - A sample of 50 half-hourly loads is used to represent the entire year (this is 0.29% of the 17,520 half-hourly loads);
  - The 50 half-hourly loads are grown to the annual energy and peak demand parameters of the 2009 ESOO.
- The incomplete set includes the key summer periods of January to February 2009 and the winter period of 2009.

2.4.2 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.

2.4.3 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 Renewable Energy Target (RET) scheme is included and we assume the RET target is satisfied by 2020 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 are shown in Table 13.

Table 13 **ACIL Tasman LRMC results**

	SRMC	LRMC	MW	GWh	Capacity factor (%)	Market share (%)	Capacity share (%)
Coal	$12.09	$50.00	4,750	37,445	90.00	63.77	46.95
CCGT	$29.97	$61.67	3,904	20,306	59.38	34.58	38.59
OCGT	$77.78	$242.68	1,463	966	7.54	1.65	14.46
Total			10,153	58,899		100.00	100.00

Data source: ACIL Tasman modelling

ACIL Tasman achieved a result for the LRMC of electricity in Queensland in 2010-11of $58.27/MWh, which includes an allowance of 3.7% to cover average transmission losses in the Queensland region of the NEM.

3 Energy purchase costs (EPC)

3.1 Background

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 can be summarised as follows:

1. Develop forecast load traces for 2010-11for::
   a) the NEM load for Queensland (small load) which is the aggregate State NEM load (large load) minus the directly connected customers load based on the recorded half hour TNI data to 30 September 2009 and the load forecast in the Powerlink 2009 APR.
   b) load traces of generation in each NEM region based on the recorded half data generation to 30 September 2009 and the load forecast in the AEMO 2009 ESOO.
2. Using the load traces for the NEM regions, carry out pool price modelling for the 2010-11 financial year providing a projection of regional reference prices (pool prices) for each half hour of the year in each region of the NEM including Queensland.
3. Calculate flat, peak and cap contracts contract volumes for each half hour of 2010-11 by applying the retailer contracting strategy developed by CRA to manage the risks in supplying the small load trace.
4. Estimate flat, peak and cap contract prices for each half hour period in 2010-11 using prices from the d-cypha Trade database.
5. Based on the half hourly pool prices for Queensland and the half hourly contract volumes and prices calculate, using a spreadsheet model, the energy cost in each half hourly for a retailer supplying the small load. The cost outcome reflects the payments made to AEMO by the retailer for pool purchases at the projected pool prices as well as difference payments paid by or to the retailer for flat, peak and cap contracts.

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

3.2 The load trace forecasts for 2010-11

3.2.1 Introduction

Using its load trace forecast program, ACIL Tasman has forecast the load traces for 2010-11 for:

- the large load for Queensland as delivered from the transmission system
- the load in each of the NEM regions at the generator terminal.

The method involved transforming:

- the actual half hourly load traces for the large load for Queensland for the year to 30 September 2009 to match the Powerlink 2009 APR forecasts of winter and summer maxim demand and annual energy for 2010-11.
- the actual half hourly load traces for generation in each NEM region for the year to 30 September 2009 to match the AEMO 2009 ESOO forecasts for summer and winter peaks and annual energy for 2010-11.

The large Queensland load trace and the NEM regional load traces for 2010-11 are perfectly aligned on a half hour basis. This ensures that half hour small load and pool prices for Queensland, which are both key inputs to the calculation of the EPC, are aligned perfectly with each other.

Large and directly connected customer for Queensland

The forecast load trace for the large load for Queensland is measured at the point of delivery from the transmission network. The small load for Queensland is the load delivered from the transmission network to customers on distribution networks and does not include the load of customers which are directly connected to the transmission network. Being metered at the point of delivery from the transmission system, the large and small loads for Queensland do not include transmission losses or energy used in power station auxiliaries.

The forecast load trace for the large load for Queensland is used in calculating the small load for Queensland which, in turn, is used to determine the contract volumes used in calculation of the EPC.

Generated load traces for NEM regions

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

The generated load in the NEM regions is used in modelling of the half hour pool prices at the regional reference nodes which are used in the in calculating the EPC.

3.2.2 Dates used in the forecast load traces.

The actual base load traces cover the period from 1 October 2008 to 30September 2009. These load traces have been changed to represent a financial year structure by moving the September Quarter 2009 from the end to the beginning of the load trace. The resultant dates in these base load traces are retained for the 2010-11 load trace forecasts. This approach does not affect the accuracy of the pool price and EPC modelling because the full range of day types to be encountered in 2010-11 are represented in the base load traces and the half hour loads in all the forecast load traces remain perfectly aligned.

Furthermore, using the base load trace day structure for the 2010-11 forecast load traces is favoured because:

- it makes no difference to the estimated pool prices, contract volumes and EPC for 2010-11
- it eliminates the possibility of errors and avoids the need to repeat days or create data in the base trace
- it ensures that the NEM regional load traces and the load traces for the large, small and directly connected customers for Queensland remain in perfect alignment.

For the EPC modelling, the forecast half hourly pool prices (which rely on the NEM regional load traces) are perfectly aligned with the half hour contract volumes (which are based on the small load trace for Queensland)

3.2.3 Half-hourly load trace data for Queensland and NEM regions

Large and directly connected customer load traces for Queensland

ACIL Tasman aggregated the half-hourly load data for all Queensland TNIs for the year to 30 September 2009, as supplied by the Authority, into:

- large load for Queensland and
- directly connected customer load for Queensland.

Financial year load trace configurations for both large load for Queensland and the directly connected customer load are then produced by moving the September Quarter 2009 from the end to the beginning of the financial year.

The load traces for both large load and the directly connected customers for Queensland are adjusted in precisely the same manner so that they remain exactly aligned with each other for every half hour. This ensures that when the directly connected customer load is subtracted from the large load it will produce a consistent half hourly load trace for the small load for Queensland which is used in establishing the contract quantities in the calculation of the EPC.

Generated load traces for the NEM regions

Load traces of as generated load for each NEM region using data to 30 September 2009 were also constructed in this way. These load traces were extracted from the AEMO website.

3.2.4 Underlying load forecasts for Queensland and NEM Regions

Large and directly connected customer load for Queensland

The following load forecasts underlying the 2010-11 load trace forecast for the large and directly connected customers for Queensland were 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.

NEM regional load

The load forecasts underlying the 2010-11 generated load trace forecasts for the NEM regions were extracted from AEMO 2009 ESOO as follows:

- **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.

3.2.5 Forecast of minimum demand

In addition the winter and summer maximum demand and annual energy, the minimum demand is used as a controlling variable in ACIL Tasman's load trace forecast program.

The 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 large load for Queensland and the generated load for each NEM region was forecast in this way.

3.2.6 Forecast load traces for large load for Queensland

The ACIL Tasman load shape forecasting model is then used to transform the half-hourly load traces for: the total load for Queensland to match the medium growth forecasts of annual energy and the minimum demand and summer and winter peak demands at 50POE, 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(large) 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.

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

3.2.7 Forecast load traces for directly connected customers for Queensland

The half-hourly load trace for directly connected customers for 2010-11 is found by applying the percentage increased or decreased contribution to summer and winter system demand of the directly connected customers as reported by Powerlink in the 2009 APR to the actual load trace as described in Section 3.2.3.

3.2.8 Forecast load traces for 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 (large) load for Queensland. The resultant forecast load trace for the small load is used in determining the flat, peak and cap contract volumes input to the calculation of the EPC.

Error! Reference source not found.Error! Reference source not found. presents the forecast minimum and maximum demand, energy and load factor from this load trace for 2010-11.

Table 14 **Maximum and minimum demand (MW), energy (GWh) and load factor (%) for the small load in Queensland – 2010-11**

	Large load MW			Directly connected (DC) load MW	NEM (Small) load MW		
	10%POE	50%POE	90%POE		10%POE	50%POE	90%POE
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	62.1%	65.3%	67.4%	94.1%	56.2%	59.5%	61.7%

Data source: ACIL Tasman analysis based on Powerlink data

3.2.9 Forecast load traces for the generated load for each NEM region

A similar approach to that outlined in Section 3.2.6 for the large load for Queensland in 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 pool prices for use in calculating the EPC.

Table 15 presents the forecast maximum demand, energy and load factor from the NEM regional load traces for 2010-11.

Table 15 **Maximum and minimum demand (MW), energy (GWh) and load factor (%) for NEM Regions – 2010-11**

	NSW	Qld	SA	Tas	Vic
Energy GWh generated					
90% POE	79,079	55,916	14,122	10,037	50,635
50% POE	79,148	55,957	14,153	10,040	50,682
10% POE	79,251	56,019	14,183	10,043	50,761
Summer Peak Demand MW generated					
90% POE	13,350	9,538	2,988	1,421	9,290
50% POE	14,290	9,852	3,238	1,437	9,884
10% POE	15,250	10,368	3,478	1,462	10,652
Winter Peak Demand MW generated					
90% POE	13,870	8,809	2,362	1,849	8,016
50% POE	14,220	8,992	2,492	1,869	8,118
10% POE	14,620	9,120	2,612	1,893	8,248
Load factor					
90% POE	65.1%	66.9%	54.0%	62.0%	62.2%
50% POE	63.2%	64.8%	49.9%	61.3%	58.5%
10% POE	59.3%	61.7%	46.6%	60.6%	54.4%

Data source: ACIL Tasman analysis based on Powerlink data

3.3 Pool price modelling for 2010-11

The market simulation modelling was undertaken using ACIL Tasman's model of the NEM known as PowerMark. Nominal prices for the fuel and other costs are used in the modelling so that the resulting RRPs are in nominal terms..

PowerMark is based on the same principles as those used by the AEMO in market settlement of scheduling, pricing and dispatch). It is a large-scale linear program (LP)-based solution incorporating features such as dynamic interconnector loss and network constraints. The veracity of modelled results relative to market outcomes 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 16 shows the quarterly RRPs from the market modelling for the 2010-11 year.

Table 16 **ACIL Tasman quarterly pool prices $/MWh – 2010-11**

	10%POE	50%POE	90%POE
Q3 2010	$40.68	$37.15	$33.93
Q4 2010	$29.85	$25.91	$25.17
Q1 2011	$57.68	$29.02	$25.82
Q2 2011	$32.19	$31.95	$29.65

Data source: ACIL Tasman PowerMark modelling

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

3.4 Contract volumes and prices

3.4.1 Contract volumes

ACIL Tasman has followed the contracting methodology developed by CRA in previous calculations of the BRCI. This methodology has been discussed with stakeholders and appears to be have become broadly agreed. The methodology is 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 in purchasing hedge contracts for the Queensland small load is:

Flat swaps	to provide flat swap contract cover up to the 80th percentile of off-peak load
Peak swaps	to provide peak swap contract cover up to the 90th percentile of peak load
$300 caps	to provide cap contract cover up to 105% of maximum peak load

Table 17 shows estimated quarterly flat, peak and cap contract volumes purchased for 2010-11 under this strategy.

Table 17 **Flat, peak and cap contract volumes MW – Q3 2010 to Q2 2011**

	Flat contract volume	Peak contract volume	Cap contract volume
Q3 2010	4,301	1,186	1,320
Q4 2010	4,912	1,300	1,450
Q1 2011	5,182	1,356	1,558
Q2 2011	4,616	1,006	1,299

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

3.4.2 Contract prices

CRA concluded that a prudent retailer is likely to purchase contracts to meet its customers' load in a given financial year by purchasing hedge contracts over the preceding two financial years. They assumed that a prudent retailer would also spread its purchases of contracts for each financial year evenly over the preceding period of two financial years. This was acknowledged by CRA as a simplification but reasonable in the circumstances.

On this basis, ACIL Tasman has also assumed that, for calculation of the 2010-11 EPC, flat, peak and cap contracts are purchased evenly over the period 1 July 2008 to 30 June 2010[7].

Quarterly flat, peak and cap contract prices for the four quarters in 2010-11 were estimated using the average of daily d-cypha Trade prices for quarterly contracts in 2010-11. The average was based on:

- the actual daily d-cypha Trade prices for the period from 1 July 2008 to 27 November 2009. ((the date the analysis was done for the draft decision)
- as well as estimated prices from 28 November 2009 to 30 June 2010. These estimated prices were taken as the average of the actual prices in the two months to 27 November 2009. This is the same methodology used by CRA in the final decision for the 2009-10 BRCI.[8]

The Final Decision for 2010-11 BRCI will be made in late May 2010 and ACIL Tasman will update the contract prices to incorporate the latest d-cypha Trade data in its final report to the Authority at that time.

Table 18 shows estimated quarterly flat, peak and cap contract prices for 2010-11.

Table 18 **Flat, peak and cap contract prices $/MWh – Q3 2010 to Q2 2011**

	Flat contract price	Peak contract price	Cap contract price
Q3 2010	$36.61	$50.18	$4.89
Q4 2010	$44.00	$64.02	$10.45
Q1 2011	$65.31	$106.73	$26.05
Q2 2011	$38.54	$47.45	$4.59

Data source: ACIL Tasman analysis using d-cyphaTrade data

3.5 Estimating the EPC for 2010-11

To estimate the EPC for 2010-11, the half hourly pool prices for 2010-11 (as discussed in Section 3.3) are brought together with the half hourly loads for the small load and the contracting prices and quantities for each half hour of the

[7] 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).

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

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 3.2, 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 EPC are shown in **Error! Reference source not found.Error! Reference source not found.**.

Table 19 **Contract settlement for the 10%, 50% and 90% POE for 2010-11**

2010-11	10% POE	50% POE	90% POE
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

ACIL Tasman calculation

Table 20 shows the estimated EPC for the 2010-11. It shows that the weighted energy purchase cost in 2010-11 is $58.72/MWh.

Table 20 **Energy purchase costs $/MWh - 2009-10 & 2010-11, scenario results, weightings and weighted values**

	Scenario weighting	(ACIL Tasman) 2010-11
Energy purchase costs ($/MWh) - 10POE	30.40%	$58.82
Energy purchase costs ($/MWh) - 50POE	39.20%	$58.61
Energy purchase costs ($/MWh) - 90POE	30.40%	$58.76
Energy purchase costs ($/MWh) - Weighted		**$58.72**

Data source: ACIL Tasman analysis

4 Other energy costs

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

The four other energy cost components discussed in the following sections, are costs associated with meeting the:

- Renewable Energy Target (RET)
- Queensland Gas Scheme
- NEM fees
- Ancillary services.

4.1 Renewable Energy Target (RET)

To determine the costs to retailers of complying with the MRET scheme, ACIL Tasman has estimated the Renewable Power Percentage (RPP) based on the targets under the expanded RET. Using weekly market prices for RECs published by AFMA, we have calculated average REC prices of $49.57/MWh in 2010 and $47.04/MWh in 2011 using the averaging methodology found in the CRA report[9]. 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 $3.01/MWh in 2010-11 and in total $113 million for the NEM load. This significant cost increase is a result of the steep increase in the RPP which in turn is a result of the higher Renewable Energy Target in 2010-11.

Table 21 shows the estimated cost of RET for 2010-11.

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

Table 21 **Estimated cost of the Renewable Energy Target $/MWh**

	2010	2011	ACIL Tasman estimate for 2010-11
RPP %	5.53%	6.98%	
Average REC price $/MWh	$49.57	$47.04	
Cost of RET	**$2.74**	**$3.28**	**$3.01**

Data source: ACIL Tasman analysis based on AFMA data

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 2.25%[10], the penalty price in 2011 is calculated to be $18.84/MWh.

On the basis that GECs account for 15% of retail load in 2011, the average cost to a retailer is $2.83/MWh in 2011. Using the cost in 2010 of $2.76/MWh from the CRA report[11], ACIL Tasman estimates the average figure for 2010-11 to be $2.80/MWh or, in total, $105 million.

Table 22 shows the estimated cost of the GEC scheme for 2010-11.

Table 22 **Estimated cost of Queensland Gas Scheme $/MWh**

	CRA estimate for 2010	ACIL Tasman estimate for 2011	ACIL Tasman estimate for 2010-11
Shortfall charge	$12.90	$13.19	$13.05
Tax-effective shortfall charge	$18.43	$18.84	$18.64
Prescribed percentage	15%	15%	15%
Total cost of Queensland Gas Scheme	**$2.76**	**$2.83**	**$2.80**

Data source: ACIL Tasman analysis based on 2010 estimates in the CRA report

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.

[10] *RBA Statement on Monetary Policy, November 2009*

[11] See page 72 of the CRA report, *Calculation of the Benchmark Retail Cost Index 2009-10* (8 June 2009).

For 2010-11, ACIL Tasman has estimated the cost of AEMO participant fees to be $0.37/MWh based on trends over the period 2007-08 to 2009-10 for which data is publicly available from AEMO's website (earlier data was not available). On this basis, we expect the total cost of NEM fees to be $14 million in 2010-11, an increase of 13.1% from 2009-10.

Table 23 shows the estimate of the NEM fees for 2010-11.

Table 23 **Estimated NEM fees $/MWh**

Cost category	ACIL Tasman estimate for 2010-11
Market participant fees	$0.28
FRC fees	$0.09
Total NEM fees	**$0.37**

Data source: ACIL Tasman analysis based on the AEMO fee schedule and revenue budget for 2007-08, 2008-09 and 2009-10

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 week of 25 November 2009), it is estimated that the cost of ancillary services will be $0.45/MWh in 2010-11, or in total $17 million.

Table 24 compares the Ancillary Services charges estimates for 2010-11 and 2009-10.

Table 24 **Estimated ancillary services charges $/MWh and $ million**

	ACIL Tasman estimate for 2010-11 $/MWh
Ancillary services	$0.45

Note: The estimate in $million is based on the estimated NEM load for 2010-11 of 37,483,145 MWh

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 2010-11 are estimated to be $6.65/MWh, or in total $249 million.Table 25 shows the estimated other energy cost for 2010-11.

Table 25 **Summary of other energy costs $/MWh**

Cost category	ACIL Tasman estimate for 2010-11
Renewable Energy Target	$3.02
Queensland Gas Scheme	$2.80
NEM fees	$0.37
Ancillary services	$0.45
Total other energy costs	**$6.65**

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

5 Energy forecast for 2009

For calculation of the BRCI for 2010-11 the Authority uses NEM load energy for 2009 calendar year. As load data for the whole of 2009 will not be available before the release of the draft decision, the Authority has asked ACIL Tasman to provide a forecast of the NEM load energy for the 2009 calendar year.

The ACIL Tasman forecast of NEM load energy for the 2009 calendar year has been achieved by:

1. forecasting the aggregate State NEM load (which includes directly connected customers) energy for 2009 by adding a forecast of the December quarter 2009 to the actual for the nine months to 30 September 2009
2. calculating the NEM load (small load) for 2009 by subtracting a forecast of directly connected (DC) load energy for 2009 from the forecast total load energy for 2009.

The Authority supplied the actual half loads for each TNI to 30 September 2009 so a forecast of December quarter 2009 was required. This forecast has been achieved by applying the average ratio between total load energy in the December quarter and total load energy in the nine months to 30 September for the four years from 2005 to 2008 to the actual for the nine months to 30 September 2009. The estimates are tabulated in Table 26 which shows the actual total load energy for the nine months to 30 September 2009 at 35,809,465MWh and the total load energy forecast for 2009 at 48,001,237MWh.

Table 26 **Aggregate State NEM load energy for 2005 to 2008 and the forecast for 2009 (MWh)**

Total load energy (MWh)	2005 (actuals)	2006 (actuals)	2007 (actuals)	2008 (actuals)	2009 (forecast)
December Quarter	12,221,013	11,822,060	11,744,793	12,181,782	12,191,772
Nine months to 30 September	34,969,503	35,788,412	34,972,871	35,185,604	35,809,465
Ratio Dec Q to nine mts to 30 Sept	34.9%	33.0%	33.6%	34.6%	34.0%
Total calendar year	47,190,516	47,610,472	46,717,664	47,367,386	**48,001,237**

Data source: ACIL Tasman analysis

The energy supplied to DC customers is very stable and on this basis the actual energy of 10,518,092MWh for the year to 30 September 2009 was regarded as a reliable forecast for 2009 for these loads.

Finally the small load energy for 2009 was forecast by subtracting the forecast energy supplied to DC customers for 2009 from the forecast of total load energy for Queensland for 2009. The resultant forecast for the NEM load energy for 2009 is 37,483,145MWh as shown in Table 27 **Forecast NEM load energy for 2009 (MWh)**

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Table 27 **Forecast NEM load energy for 2009 (MWh)**

Energy (MWh)	Total Load	Directly connected customers	NEM load
2009	48,001,237	10,518,092	37,483,145

Data source: ACIL Tasman analysis

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 SOO 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	Unranquinty	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, AEMO 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 AEMO 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 pool price movements across the volume of these contracts except where pool price 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 pool price will tend to spiral downwards and future contracts will tend to reflect lower pool price expectations. Hence long term optimal strategies require some generation to be bid above SRMC to maintain underlying pool prices 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:

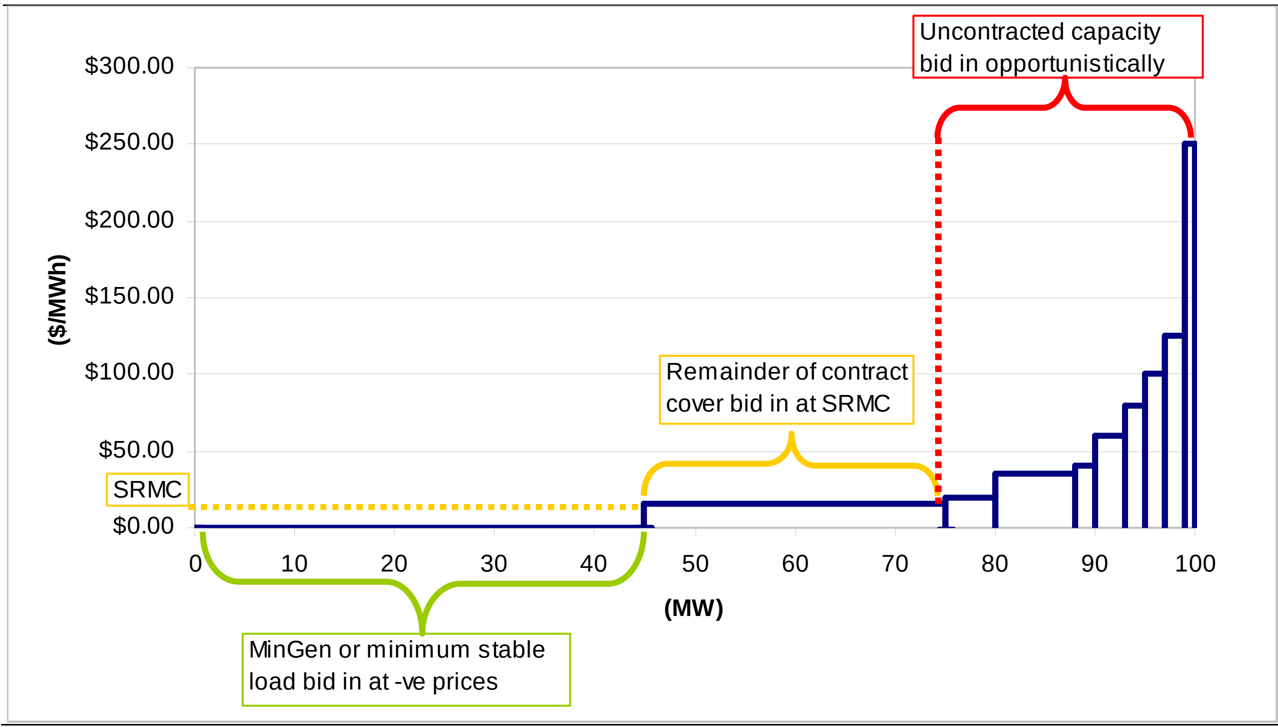
- the assumed level of MinGen, which is offered between -$1000/MWh and $0/MWh; and
- the assumed level of contract cover, which is offered at the SRMC of the plant.

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 2 **Example offer curve of a generator**



Data source: ACIL Tasman

A.3 Contract cover

Contract cover measures the extent to which generators have their pool price exposure covered by financial swap contracts (two-way hedges)[12]. 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[13]), 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 pool prices 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 pool prices when actual demand data and outage data are

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

13 '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 pool price 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 pool prices are expected to be higher.

substituted 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 AEMO 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*