Energy costs for Queensland electricity tariffs in 2007/08 and 2008/09

Input assumptions for estimating the long run marginal cost of generation in Queensland in the context of QCA regulated electricity tariffs

Prepared for AGL Energy

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ACIL Tasman

Economics Policy Strategy

Reliance and Disclaimer

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1 Introduction

ACIL Tasman has been engaged to assist AGL Energy (AGL) in preparation of its submission to the Queensland Competition Authority (QCA) regarding the determination of the energy component of the cost of supply of the Queensland load for 2007/08 and 2008/09.

The work completed by ACIL Tasman is to be used by AGL in developing a submission to the QCA in response to the interim report prepared by CRA International (CRA), on behalf of the QCA, titled *Calculation of the Benchmark Retail Cost Index for 2007-08 and 2008-09*.

The scope of the project can be considered in two broad terms:

- Develop, from first principles, an estimate of the long run marginal cost (LRMC) of the efficient mix of power plant to satisfy the Queensland load in 2007/08 and 2008/09 (the generation cost);
- Review the estimation methodology, input assumptions and results of the generation cost estimate reported by CRA.

Although the interim CRA report covers all aspects of the Benchmark Retail Cost Index (BRCI), ACIL Tasman has been engaged by AGL to consider the energy cost component of the BRCI.

It is important to note that ACIL Taman has not been engaged to review the methodological framework adopted by the QCA and in this context ACIL Tasman has taken the framework as a given.

This report sets out:

- the modelling methodology; and
- the input assumptions.

2 Methodology

The approach adopted by ACIL Tasman to estimate the efficient plant mix and cost of generation in Queensland can be considered as the following key steps:

- Update our estimates on the components of the short run marginal costs of the dominant technologies in Queensland for 2008/09;
- Update our estimates on the components of the long run marginal costs of the dominant technologies in Queensland 2008/09;
- Use our internal DCF model to estimate the long run marginal cost of individual plant for 2008/09;

- Use the estimated SRMCs and LRMCs, together with an assumed set of half hourly loads as input to our plant mix allocation model to derive the efficient plant mix for a given year and the corresponding cost of generation for 2007/08 and 2008/09.

It is worth noting that the methodology used to update our estimates of the input components of the short run and long run marginal costs is the same as the one used in our 2007 report to NEMMCO, titled *Fuel resource, new entry and generation costs in the NEM Report 2 – Data and documentation* (the NEMMCO report or the 2007 estimates). However, the treatment of tax within our DCF has changed slightly based on feedback from industry participants in 2007 post release of the 2007 NEMMCO report.

The plant mix allocation model is essentially a partial equilibrium model which maps the long run marginal cost of individual technologies onto the load duration to determine the least cost plant mix. This method also appears to be used by CRA for the QCA.

Constraints are added to the model such as the current reliability requirement of 0.002% of lost load. The model produces the efficient plant mix which produces the least cost of generation and also produces the hourly dispatch profile of each technology. The hourly dispatch profile is useful for sensibility checking and allows identification of additional constraint requirements.

However, unlike CRA, our model is static in the sense that it estimates the efficient plant mix for a given year of hourly loads and input costs. The model is not 'forward looking' or 'backward looking', and therefore makes no attempt to find an evolving plant mix to produce the least cost of generation over a several decades.

ACIL Tasman notes that CRA uses a forward looking 20-year modelling horizon. However, we do not see the value add in this approach. This approach takes into account the change in the load duration curve over time as well as evolving capital costs and technology. However, we only see value in taking this approach if it is known that there will be, in the future, a fundamental change in the load shape or capital costs.

A changing load duration curve, for example a load duration curve that evolves to become peakier than present, may result in additional peaking plant being added to the system but given the short development time associated with peaking plant, the additional plant will only be added when required. Conversely, if the load shape were to become very flat then it may be possible for potential investors in peaking plant, today, to look forward and decide to not proceed with a new entrant peaking plant. The forward looking approach would certainly identify this issue and adjust the plant mix accordingly.

However, the load projection assumed by CRA (based on the NEMMCO SOO) does not display a step change in the shape of the load profile.

Further, a reasonable question to ask is: why use a forward looking approach only, why not start the modelling horizon 20 years in the past? And thereby model the (theoretical) evolution of the efficient plant mix from a historical stand point, so that 2007/08 and 2008/09 sit in the middle of the projection period, which has equal merits to the forward only looking approach.

3 Input assumptions

3.1 Introduction

This section of the report sets out ACIL Tasman's estimates of the input assumptions required to estimate the cost of generation. Our estimates of input costs for generation uses as a starting point our 2007 report to NEMMCO. The cost estimates from the 2007 NEMMCO report are continued to be used as inputs for the cost of generation in 2007/08. The updated cost estimates, derived below, are used for the estimation of the cost of generation for 2008/09.

3.2 Project capital costs

Project capital costs for a new power station include:

- engineering, procurement and construction (EPC)
- planning and approval
- professional services
- land acquisition
- infrastructure costs (incl. water)
- spares and workshop etc and
- connection to the electricity network,
- fuel connection, handling and storage and
- mining infrastructure and development for coal fired developments.

Capital costs are usually expressed in $/kW.

3.2.1 CCGTs

In the NEMMCO report our estimate of project capital costs for CCGT plant for 2007/08 was AUD$1,050/kW installed.

Since the NEMMCO report there has been a small number of projects in Australia and New Zealand as shown below. It is quite apparent that costs have continued to increase during the past 12 months. This trend is supported by data from other countries and sources, as also noted by CRA, and reflects the continued increasing demand for turbines.

Based on our analysis of these recent projects, including an assumption of a 15% discount for the Tamar Valley brownfield project, **we estimate that the current cost for a greenfield CCGT project is AUD$1,200/kW**. This represents about a 14% increase from our estimate published in the NEMMCO report.

Table 1 **Project capital costs for recently announced CCGT projects in Australia and New Zealand**

Project	Cost (AUD$/kW, 2007/08 $)	Source	Comments
Condamine, 140MW	$1,214/kW	Various QGC ASX announcements	
Tamar Valley, 210MW	$1,095/kW	Various Alinta ASX announcements	Brownfield site
Huntly, NZ, 385MW	$1,148/kW	http://www.power-technology.com/projects/#top	
Darling Downs, 630MW	$1,238/kW	Origin Energy website	

Data source: ACIL Tasman analysis of various sources

ACIL Tasman notes that in Singapore in early 2007, the regulator as part of its determination into the LRMC of generation revised the capital cost of a CCGT by an increase of 33% between 2005-2006 and 2007-2008 – about a 16% increase per year, which is slightly greater than the 14% increase we estimate for Australian projects.

Similarly, the Edison Foundation report titled, *Rising Utility Construction Costs: Sources and Impacts*, September 2007, estimates that gas turbine costs increased by about 16% in 2007, which is again consistent with our estimated 14% increase. It is worth noting that the Edison Foundation report makes reference to the US Energy Information Administration's 2007 *Annual Energy Outlook* (AEO) and makes a similar observation to that of CRA, that is – "*capital costs of all technologies are assumed to grow at the general price level* [in the AEO] – *a pattern that contradicts the market evidence presented in this report*" (page 3 of *Rising Utility Construction Costs: Sources and Impacts*, September 2007, Edison Foundation).

3.2.2 OCGT

In the NEMMCO report our estimate of project capital costs for OCGT peaking plant for 2007/08 was AUD$720/kW installed.

Since the NEMMCO report there has been a small number of projects in Australia as shown below. It is quite apparent that costs have continued to increase during the past 12 months.

ACIL Tasman is aware of the option to include a heat recovery unit (but not with a steam turbine) and this is understood to improve the thermal efficiency to about 40% and of course, increase the capital costs. We understand that this option is being considered by some project proponents, although it is difficult to confirm which projects have included this option.

Given the information in the table below, **we estimate that the current cost for a greenfield OCGT project is AUD$900/kW.** This represents about a 20% increase from our estimate published in the NEMMCO report.

Table 2 **Project capital costs for recently announced OCGT projects in Australia**

Project	Cost (AUD$/kW, 2007/08 $)	Source	Comments
Braemar OCGT - Stage 2	$1,011	Courier Mail Feb 2008	Removed AUD$90M for pipeline. Appears to include a heat recovery unit.
Mt Stuart expansion	$730	Origin ASX release - Feb 2008	Expansion.
Neerabup	$1,091	Babcock & Brown website	Removed AUD$65M for pipeline.
Colongra	$610	Platts	EPC only.
Tamar Valley OCGT	$891	Alinta website	Brownfield site

Data source: ACIL Tasman analysis of various sources

3.2.3 Black coal supercritical plant

In the NEMMCO report our estimate of project capital costs for black coal supercritical plant for 2007/08 was AUD$1,700/kW installed.

Unfortunately, with the prospect of emissions trading and the proliferation of CSG resources, there are no new data on supercritical project costs in eastern Australia in the public domain. Griffin Energy is developing the 208MW Bluewaters I project in Western Australia at a cost of AUD$400M (according to the Griffin Website), which is equivalent to AUD$1923/kW.

The Edison Foundation report titled, *Rising Utility Construction Costs: Sources and Impacts*, September 2007, suggests that conventional coal station project capital costs increased by about 12% in 2007. Applying a 12% increase to our 2007/08 estimate of $1,700/kW would result in a cost of AUD$1,900/kW, which is consistent with the cost of Bluewaters.

One would expect the increase in supercritical coal project costs to be within the ‘same ballpark’, in percentage terms, as the increase in CCGT costs. Indeed, ACIL Tasman is well aware of non-published confidential evidence that capital costs for supercritical projects in the Asia-Pacific region have increased over the past 12 months at a rate greater than the increase in the CCGT capital costs (that is, greater than 14%). However, this evidence cannot be used in this particular instance - although it does provide a sensibility check against the publicly available information. Therefore, on the basis of evidence in the public domain (the Edison Foundation report and Bluewaters I), **we estimate that the current cost for a greenfield supercritical coal project is AUD$1,900/kW.** This represents about a 12% increase from our estimate published in the NEMMCO report.

3.2.4 Summary

The table below sets out our estimates of project capital costs for 2008/09, and also includes the previous estimates used for 2007/08.

Table 3 **Estimated project capital costs for new build plant**

Year	Cost (AUD$/kW, nominal)		
	CCGT	OCGT	Coal
2007/08	$1,050/kW	$720/kW	$1,700/kW
2008/09	$1,224/kW	$918/kW	$1,938/kW

Data source: ACIL Tasman analysis of various sources

3.2.5 Comments on the CRA/QCA assumptions

The interim CRA report notes that capital costs are most likely to have increased since the publication of the ACIL Tasman 2007 report for NEMMCO, making use of various international references and suggests that the 2007 ACIL Tasman estimate of AUD$1,700/kW for supercritical coal plant is likely to be a significant underestimate. However, CRA note that there is little information in the public domain to support a change in our 2007 estimate. In fact, CRA have continued to use our 2007 estimates rather than attempt to make a reasonable judgement themselves of the increase in capital costs.

ACIL Tasman finds that there is clear and sufficient evidence in the public domain to show that capital costs have increased by about 15% over the past 12 months in the Australian context.

The methodological framework for determining the BRCI appears to support using the capital costs of the day, as shown by application of the 2007 ACIL Tasman estimates by CRA/QCA in the 2007 determination. If this is the case, then the capital costs should be updated.

3.3 Fuel costs

For Queensland the relevant fuels are black coal and gas. We note that CRA has used the ACIL Tasman estimates contained in the 2007 NEMMCO report. However, our view on fuel pricing has changed over the past 12 months.

3.3.1 Coal

Coal fired generating plant is either located at mine mouth or distant from mine and coal is usually transported by rail. In determining an average coal coast, we also include the associated costs of storage, handling, milling and ash disposal to reflect a burner tip price.

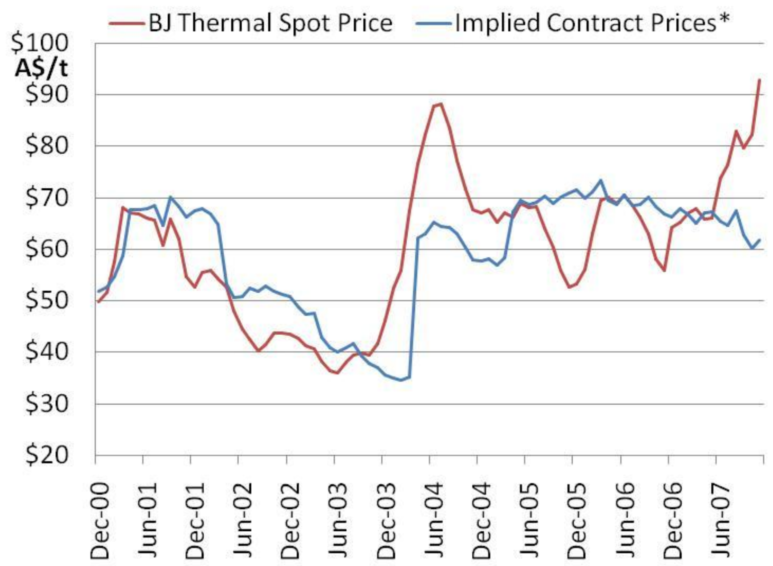
The pricing issue is complicated by large increases in the market (and spot) price of steaming coal, largely driven by the large increases in demand for coal in Asia. Until recently, coal producers supplying domestic power stations have been disconnected from the international coal market. However, there is a growing trend towards price parity, which is putting upward pressure on domestic coal prices, even for coals traditionally considered of lower quality (for example, high ash).

The average spot price for thermal coal increased 15.5% in the first 11 months of 2007, compared with the same period in 2006. The current spot price of AUD$92.86/t is 36% higher than the contract price, negotiated between Australian thermal coal suppliers and Japanese power generating companies in March 2007 (see Figure 1).

The price increases in 2007 was driven by major supply disruptions over the year. These constraints are not expected to be fully resolved before the next round of negotiations for the 2008-09 JFY in February/March 2008. Usually the contract prices are set very close to the spot price in those months, as can be observed from the 2006-07 and 2005-06 JFY contract prices.

However, although the current spot price is significantly above the underlying market price, the 2008-09 JFY contract price is likely to be negotiated at significantly lower levels than the current spot price, given that a number of constraints which have led to very high recent prices are now well on the way to resolution. However, both the ongoing supply demand balance and higher production costs will limit the downward pressure.

Figure 1 **BJ Thermal Coal spot price ex Newcastle vs. Contract prices**



** Implied contract prices based on $US JFY contract prices deflated by exchange rate*

Data Source: Barlow Jonker 2006: Australian Coal Report

The spot price should come down significantly throughout 2008 as a result of increased supply into the market supported by increased infrastructure capacity. In the medium term, prices should return to a more fundamental level. However prices will remain well above historic levels with mining cost structures increasing in the latest round of expansions across the industry.

Reviewing current data, coal suppliers were willing to settle for a bottom range contract price of around USD$56/t. Australian thermal coal suppliers to the Japanese power utilities have been seeking prices of around USD$70/t for yearly contracts starting 1 October 2007, which probably gives a better indication of where the market is heading. Furthermore, the current increases in the Australian dollar exchange rate will have detracted from the competitiveness of coal export producers, narrowing their price range for negotiations.

A recent report by Merrill Lynch[1] forecasts a thermal coal contract price of USD$80/t for 2008-09 JFY (starts 1 April), an increase of 23% on the current year, largely due to higher spot prices. However, their longer term forecast is for a contract price of USD$50/t after 2012-13 JFY, with prices of USD$80/t, USD$70/t, USD$60/t and USD$55/t for the four years starting 2009-10.

Based on a USD$60/t as a reasonable FOB contract coal price for 2008-09, with a 20% discount applied for domestic coal and handling costs of

1 Australian Financial Review, 19/12/07, p19.

AUD$15/t (port charges and indicative rail freight), the delivered coal cost is **AUD$1.54/GJ**, based on AUD$=0.85USD$ and energy content of 27 GJ/t.

This represents a $0.70/GJ increase from the 2007-08 forecast coal price into Queensland power stations in the 2007 NEMMCO report ($0.84/GJ), which appears to be currently used by CRA. This indicative coal price does not reflect the diversity between the various potential coal fields or the fact that some coal deposits are ineligible to be compared to export parity prices due to their remote location or quality.

3.3.2 Gas

Queensland has around 1,550 MW of gas-fired capacity currently installed as shown in Table 4, with numerous proposals to augment this capacity in future years. Swanbank E, Townsville and the recently completed Braemar station account for the majority of the region's gas-fired output.

There are other committed proposals, including:

- Origin's 630MW CCGT for Darling Downs
- Braemar II, with an additional 450MW of peaking plant – planned to operate with a 25% capacity factor using 11.5 PJ/a
- QGC's Condamine 130MW CCGT

Table 4 **Existing and committed gas-fired power stations in Queensland**

Station	Type	Configuration	Size (MW)	Registered capacity (MW)
Barcaldine Power Station	CCGT	OCGT (1x37 MW), Steam turbine (1x18 MW)	57	55
Braemar Power Station	Gas turbine	OCGT (3x168 MW)	504	504
Oakey Power Station	Gas turbine	OCGT (2x141 MW)	282	282
Roma Gas Turbine Station	Gas turbine	OCGT (2x40 MW)	80	80
Swanbank E	CCGT	CCGT (1x385 MW)	385	385
Townsville Gas Turbine	CCGT	OCGT (1x165 MW), Steam turbine (1x82 MW)	247	242
Total			**1,555**	**1,548**

Data source: ACIL Tasman, NEMMCO List of generators and scheduled loads in the national electricity market (updated 7 January 2007)

While there are several current gas fired plants in various locations requiring gas supply from different fields, the delivered price of gas is most strongly influenced by the type of gas plant – an OCGT (or peaker) or CCGT, based on the supply chain costs of gas production and transportation.

Gas pricing is complicated by the current focus by CSG producers on developing gas reserves to supply a number of proposed LNG plants in Gladstone. In recent years, the focus of these emerging CSG producers

(Arrow, QGC etc) has been to secure volume contracts to underwrite expansion with less focus on profitability. That situation has changed now with the intention to achieve higher margins through supplying gas for power generation or to other value added opportunities (LNG, gas-to-liquids etc). In view of the environmental benefits offered by gas fired plant over coal, with CO2 emissions reduced by around 50%, gas fired generation is also viewed as a key component to achieve any emission reduction targets and will therefore be priced higher than without a ETS from around 2010.

While market modelling of supply/demand and the gas supply curve of each producer provides gas prices of around $3.25/GJ as a defacto delivered gas price for a CCGT located in Braemar, we believe this understates the opportunity cost perceived by producers and suggest a more reasonable price is **$3.75/GJ**. This assumes intermediate operation with a gas supply load factor of 80%. A power station based at a CSG field will avoid any transportation costs and therefore reduce the gas price into power station by around $0.70/GJ, depending on distance between gas field and power station.

This forecast gas price is considerably higher than the $2.74/GJ for 2007/08 in the 2007 NEMMCO report, which appears to be currently used by CRA, and reflects the significant changes that have occurred in the outlook for gas demand (LNG market opportunity and fuel of choice to reduce emissions) and higher gas supply costs, driven by a shortage of wells and higher labour costs.

For an OCGT, with a load factor of around 5-15%, the delivered gas price needs to be increased to around **$5.50/GJ**, to reflect the higher supply chain costs, including pipeline capacity reservation costs and reflecting the difficulties for a CSG producer to vary delivery from developed wells.

It is difficult to propose a single gas supply cost for Queensland based on the geographical spread and the degree of integration between some producers allows for transfer pricing eg. gas for the proposed 630MW CCGT by Origin Energy for Darling Downs can be priced very cheaply to ensure a high capacity factor (based on a low SRMC), with profits available from gas production, power generation or retail energy sales. Alternatively, gas supplied at arm's length to a power generator will cost more and offers none of the portfolio benefits available to an integrated producer/generator.

3.4 Fixed O&M costs

Fixed O&M costs include maintenance, operating, and overhead costs that are not dependent on the hour-by-hour level of generation from the station.

ACIL Tasman's estimates of fixed O&M costs are provided in the table below. Our view on the fixed costs for the existing technologies has evolved over time and has been subjected to review from a large number of clients. These estimates are unchanged from the 2007 NEMMCO report.

Note that these estimates are presented as a cost per MW of installed capacity (not sent-out capacity).

Table 5 **Estimated fixed O&M cost (AUD per MW of installed capacity) in 2007-08 and escalation rate**

Technology	AUD$/MW/year	Escalation rate (% of CPI)
CCGT	$12,800	100%
Supercritical – black coal	$40,000	100%
OCGT	$7,500	100%

Data source: ACIL Tasman analysis

3.5 Variable O&M costs

ACIL Tasman's estimates of variable O&M costs are provided in the table below. The estimates for variable costs for the existing technologies has evolved over time and incorporates analysis of NEM offer curves to deconstruct the SRMC cost components. Our estimates have been subjected to review from a large number of clients. These estimates are unchanged from the 2007 NEMMCO report.

It is important to note that the variable O&M cost for a CCGT is based on a 65% capacity factor – the typical capacity factor observed for CCGTs in the NEM to date. The Connell Wagner report to the recent Owen Inquiry suggests that our estimate was too high, but Connell Wagner made the incorrect assumption that our estimate was based on a 90% capacity factor. ACIL Tasman has recent experience consulting in the Singapore electricity market in which CCGTs do operate in baseload mode and consequently have a lower variable O&M of about $1/MWh; however, the fixed O&M costs are correspondingly higher in Singapore. Therefore, ACIL Tasman is comfortable with the assumed O&M costs reported in this document.

Note that these estimates are presented as a cost per MWh sent-out.

Table 6 **Variable O&M cost (AUD/MWh, sent-out) in 2007-08 and escalation rate**

Technology	AUD$/MWh	Escalation rate (% of CPI)
CCGT	$4.85	100%
Supercritical – black coal	$1.20	100%
OCGT	$7.50	100%

Data source: ACIL Tasman analysis

3.6 Thermal efficiency and internal usage (auxiliaries)

ACIL Tasman's estimates of auxiliaries are provided in the table below. The estimates have been based on published sent-out and generated output by existing NEM generators feedback from clients.

Table 7 **Auxiliaries usage (%) for new entrants**

Technology	Auxiliaries usage
CCGT	2.4%
Supercritical – black coal	7.5%
OCGT	2.0%

Data source: ACIL Tasman analysis

ACIL Tasman's estimates of thermal efficiency are provided in the table below. Our view on the thermal efficiency for the existing technologies has evolved over time and includes analysis of offer curves of existing plant to deconstruct the SRMC cost components. The estimates have been subjected to review from a large number of clients.

Table 8 **Thermal efficiency (HHV, as sent out) for new entrants**

Technology	Thermal efficiency
CCGT	52%
Supercritical – black coal	42%
OCGT	31%

Data source: ACIL Tasman analysis

3.7 Plant availability

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

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

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

ACIL Tasman proposes to use an availability of 90% for coal plant. This appears to be consistent with the CRA assumption.

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 proposes to use an availability of 92% for CCGT plant**. This is about 2 percentage points lower than the CRA assumption.

ACIL Tasman assumes a 3% forced outage rate for peaking plant. Although peaking plant do undergo planned maintenance, we do 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 seems 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 97% for OCGT plant. This is about 6 percentage points higher than the CRA assumption.

3.8 Discount factor – WACC

The discount factor (or WACC) is derived using the components shown in the table below. The only change in the inputs, when compared with our 2007 estimates, is the Treasury T-bond rate which is assumed to be 6.14% (based on the average rate over the past 3 months) compared with the 2007 assumption of 5.7%.

We estimate the current post tax real WACC to be 6.93%, an increase from the 2007 estimate which was 6.58%. We note that CRA continue to use our 2007 estimate.

Table 9 **WACC parameters**

	Parameter	Value
D+E	Liabilities	100%
D	Debt	60%
E	Equity	40%
rf	Risk free RoR	6.14%
MRP = (rm-rf)	Market risk premium	6.00%
rm	Market RoR	11.70%
T	Corporate tax rate	30%
Te	Effective tax rate	22.5%
Tc	Imputation adjusted tax	15.0%
	Debt basis point premium	200
rd	Cost of debt	7.70%
G	Gamma	0.50
ba	Asset Beta	0.80
bd	Debt Beta	0.16
be	Equity Beta	1.75
re	Required return on equity	16.21%
F	Inflation	2.50%
	Post tax real WACC (Officer)	6.93%

Data source: ACIL Tasman and various sources

3.9 Build time and project life

For the purpose of calculating the long run marginal cost of a new plant a project life of 30 years has been assumed. The build time assumed for each type of technology is shown in the table below. These assumptions are the same as in the 2007 NEMMCO report.

Table 10 **Construction profile (% of project capital cost)**

Technology	Year -4	Year -3	Year -2	Year -1
CCGT	0%	0%	40%	60%
Supercritical – black coal	10%	20%	35%	35%
OCGT	0%	0%	0%	100%

3.10 Unit size

The table below shows the assumed unit size for each technology. ACIL Tasman understands that this is the same as assumed by CRA.

Table 11 **Assumed unit size (MW, installed)**

Technology	MW
CCGT	380MW
Supercritical – black coal	450MW
OCGT	150MW

Data source: ACIL Tasman

3.11 Treatment of GECs

ACIL Tasman notes that CRA assumes GEC prices remain at the penalty, which equates to $16.93/MWh in 2007/08 and $17.36/MWh in 2008/09. These assumed prices are reasonable if the resulting optimal plant mix outcome results in gas fired generation meeting close to 13% of the liable load.

There are two possible approaches to the treatment of the GECs within the plant mix allocation model. One is to reduce the SRMC of the CCGTs by the value of the GEC. In the NEM, existing CCGTs typically reduce their SRMC in their bidding by the GEC value to maximise the combination of pool revenue and GEC revenue (reducing the SRMC by the GEC price lowers bid curve which in turn increases dispatch and hence the number of GECs produced). This approach makes sense when there is only a small number of CCGTs; if there were a large number of CCGTs then this approach would likely reduce pool prices substantially and flood the GEC market with too many GECs. Under this approach, the GEC price would then need to be added back to the resulting cost of generation based on the total number of MWh generated by the CCGT plant.

The second approach is not to reduce the SRMC of the CCGTs by the GEC value and simply run the plant mix allocation model with the vanilla SRMC for the CCGTs. In this approach the GEC price would be added on to the cost of generation at a rate of 13% of the liable load.

We adopt the second approach. It is not necessary to reduce the SRMC of the gas plant by the GEC value as this will result in CCGTs being the dominant technology thus flooding the GEC market and pushing GEC prices down to a value of close to zero.