NSW Department of Planning

Independent Review of Greenhouse Gas Assessments

Bayswater B EA Concept plan

FINAL

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Bayswater B EA Concept plan

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1 Introduction

Arup has been commissioned by the NSW Department of Planning to undertake an independent review of the Greenhouse Gas Assessment produced as part of the Environmental Assessment (EA) for the Bayswater B Power Station Extension Concept Plan. The Greenhouse Gas Assessment has been prepared by AECOM on behalf of Macquarie Generation. The following presents Arup's findings and recommendations to the Department of Planning to assist in the determination process for the Concept Plan.

1.1 Project Overview

Macquarie Generation is seeking concept plan approval to increase the generation capacity of the existing Bayswater Power Station off the New England Highway, approximately 10km south of Muswellbrook, NSW. The four existing 660MW coal fired generators at the site were originally commissioned in 1985. Concept plan approval is now being sought for two potential options to expand the generation capacity to:

- Coal fired option – 2 × 1000MW Ultra Supercritical (USC) coal fired power generators; and
- Gas fired option – 5 × 400MW Combined Cycle Gas Turbines (CCGT).

Should the Concept Plan be approved, it is anticipated that the final option would be determined by a future project proponent (who may or may not be Macquarie Generation) and would be subject to approval under a separate Project Application to the Department of Planning.

The Concept Plan Environmental Assessment is currently on public exhibition.

It should also be noted that two other applications for base load coal and/or gas fired electricity in NSW have been concurrently submitted to the Department of Planning[1].

1.2 Director General Requirements

Director General Requirements for the EA were issued on 4 July 2009. Greenhouse gases were identified as a key issue with key assessment requirements as presented in Box 1 below.

BOX 1: DIRECTOR GENERAL'S REQUIREMENTS FOR GREENHOUSE GAS ASSESSMENT

The Environmental Assessment must include a comprehensive greenhouse gas assessment undertaken in accordance with the methodology specified in the *National Greenhouse Accounts (NGA) Factors* (Department of Climate Change, November 2008) including:•

- *Quantification of emissions* (in tonnes of carbon dioxide equivalent) in accordance with the Greenhouse Gas Protocol: Corporate Standard (World Council for Sustainable Business Development & World resources Institute) including direct emissions (Scope 1), indirect emissions from electricity (Scope 2) and any significant up or down stream emissions (Scope 3) considering all stages of the project (construction, operation and decommissioning).
- *Comparison* of predicted *emissions intensity and thermal efficiency* against: best achievable practice and current NSW averages for the activity, and of predicted emissions against total annual national emissions (expressed as a percentage of the total national greenhouse gases produced per year over the life of the project).
- *Evaluation* of the availability and feasibility of *measures to reduce and/ or offset the greenhouse emissions* of the project including options for carbon capture and storage.

[1] Mount Piper Power Station Concept Plan (2000MW USC coal fired or CCGT) http://majorprojects.planning.nsw.gov.au/index.pl?action=view_job&job_id=3325 and Munmorah Power Station Rehabilitation Project Application (700MW USC coal or CCGT) http://majorprojects.planning.nsw.gov.au/index.pl?action=view_job&job_id=3324

Where current available mitigation technology is not technically or economically feasible, the Environmental Assessment must demonstrate that the proposal will use best available technology, including carbon capture readiness, and identify options for triggers that would require staged implementation of emerging mitigation technologies.

- *Evaluation* of the project in the light of carbon emission prices of $10, $25 and $50 per tonne *under the proposed Commonwealth Carbon Pollution Reduction Scheme*, both with and without proposed mitigation measures.

1.3 Arup Independent Review

1.3.1 Scope

The independent review has been prepared to meet the requirements of the “Consultants Brief” for the project issued by the Department of Planning including review of:

- the technical adequacy and completeness of the Proponents’ greenhouse gas assessment including methodology and modelling assumptions;
- whether the emission efficiencies identified constitute what can be reasonably and feasibly achieved at the respective sites taking into account generation technologies and site constraints;
- whether the mitigation options identified provide an accurate representation of currently available reasonable and feasible mitigation technology that can be incorporated into the projects and of emerging mitigation technology that may be applicable to the projects in the future; and
- recommended conditions that may be applied to the projects to minimise and/ or offset greenhouse gas impacts consistent with best practice.

1.3.2 Structure

The independent review is structured under the four issues identified in the DGRs:

- Section 2: Quantification of emissions
- Section 3: Comparison of predicted emissions intensity and thermal efficiency
- Section 4: Evaluation of measures to reduce and/ or offset the greenhouse emissions
- Section 5: Evaluation of the project under the proposed Commonwealth Carbon Pollution Reduction Scheme

Under each heading the independent review provides a review of the technical adequacy and completeness of the methodology and modelling assumptions. For Section 3 to Section 5 an independent comparison/evaluation of the project is also provided as part of a merits review.

In addition, Section 6 provides recommendations for conditions that may be applied to the projects to minimise and/ or offset greenhouse gas impacts.

1.3.3 Assumptions and Limitations

The independent review is based on the Environmental Assessment (EA) prepared by AECOM and assumes that the information provided is neither false nor misleading.

In addition the review provides an evaluation of possible future scenarios under which the project may be undertaken. The future scenarios have been based on publicly available data including a number of models relating to the future costs and deployment of technologies and the future of a carbon trading market in Australia. The future scenarios are therefore subject to the assumptions and limitations within these models and contain a degree of uncertainty.

2 Quantification of Greenhouse Gas Emissions

2.1 Scope of assessment

The GHG assessment defines the scope of the greenhouse gas assessment to include all emissions of greenhouse gases (six Kyoto gases) occurring within the project boundaries. The project boundaries include upstream, downstream and on site processes associated with construction, and operation of the power station.

In accordance with the Director General Requirements, the assessment categorises the emissions as either Scope 1, Scope 2 or Scope 3. Scope 1 emissions are defined by the assessment as those emissions occurring directly on site. Scope 2 emissions are defined as emissions resulting from the consumption of purchased electricity. Scope 3 emissions include all other upstream and downstream emissions including those emitted during construction and decommissioning as well as other offsite processes associated with operation.

2.2 Methodology

The GHG assessment states that emissions have been calculated in accordance with National Greenhouse and Energy Reporting scheme (NGERs)[2] and National Greenhouse Accounts (NGA) Factors[3] methodologies as requested by the DGR. However, none of the emissions quantification calculations are shown within the GHG assessment or main body of the EA. Arup has had to compare the results to data published from other sources and by assuming different emission factors have been used.

2.2.1 Scope 1 emissions

The GHG assessment has estimated that Scope 1 emissions will total 12,147,060 tCO_2e per annum in operations and 60 tCO_2e per annum in construction for the coal fired option and 5,771,040 tCO_2e per annum in operations and 40 tCO_2e per annum in construction for the gas fired option. The operational Scope 1 emissions are dominated by emissions from the combustion of fuel on site in both the coal fired and gas fired options.

Combustion of fuel

The Scope 1 emissions from the combustion of fuel as estimated by the GHG assessment would be 12,147,000 tCO_2e per annum for the coal fired option and 5,771,000 tCO_2e per annum for the gas fired option.

The GHG assessment states that emissions from combustion of gas or coal for electricity generation have been calculated using Method 2 from the NGER Guidelines. This method is defined as "*a facility-specific method using industry sampling and Australian or international standards listed in the Determination or equivalent for analysis*"[2].

Although a total estimate is given for emissions from fuel combustion and transport use, not all of the inputs to the estimate calculations have been included in the GHG assessment. Some further details are contained in the main body of the EA (Section 5.2.8 Coal Fired Plant Operating Parameters and 5.3.8 Gas Fired Plant Operating Parameters) which has allowed some of these calculation inputs to be determined for the purposes of this review.

Emission factors published as part of the Generator Efficiency Standards, NGA factors or NGERS have been used in instances where data is not present in the GHG assessment in order to review the estimates.

[2] *National Greenhouse and Energy Reporting (Measurement) Determination* 2008 under subsection 10(3) of the *National Greenhouse and Energy Reporting Act* 2007
[3] Department of Climate Change, 2009, *National Greenhouse Accounts Factors 2009*

Coal fired option

The proposed source of the coal fuel supply is not specified within the GHG assessment of the main body of the EA. Section 5.2.2 in the main body of the EA suggests that the source of the coal has not been as yet been identified when it states *"the proposed Bayswater B project would require up to approximately 6.3 million tonnes of coal per year, dependent on the specific energy value of the coal, which could vary the final volume required".* Given the implied uncertainty surrounding the specific coal source to be used it is unusual that NGER Method 2 was used to calculate emissions as it is facility and fuel specific. NGERS Method 1 provides generic estimates that could be used in instances where exact characteristics of the fuel are unknown.

The coal fuel data contained in the main body of the EA gives several of the details of the proposed fuel to allow for an adequate quantification of emissions from fuel combustion. However, one crucial data input to the emission calculation is missing. This is the amount of carbon in the fuel type, that is the percentage of the dry, ash-free mass of the fuel estimated using sampling and analysis[4]. Using the default carbon in coal on a dry ash free basis figure contained in the Generator Efficiency Standard (GES) intensity calculator of 87% and the figures supplied in the main body of the EA the comparison in the following table was calculated.

Table 1 Quantification of emissions from fuel combustion - coal fired option

NGERS terminology	NGERS Method 2		NGERS Method 1
	GHG Assessment	Using GES figures	
Quantity of fuel (t p.a)	6,300,000	6,300,000	5,063,333*
Energy content (Gj/t)	21.7	21.7	27.0
Moisture (%)	9.40	9.40	NA
Ash (%)	26.15	26.15	NA
Carbon in ash (%)	3.00	3.00	NA
Carbon in coal on a dry, ash free basis (%)	Not shown in EA	87.00	NA
Carbon in fuel (%)	Not shown in EA	56.07	NA
Fuel emission factor ($kgCO_2e/kg$)	Not shown in EA	2.03	NA
Fuel emission factor ($kgCO_2e/Gj$)	Not shown in EA	93.4	88.43
Emissions (tCO_2e p.a)	12,147,000	12,765,692	12,089,265
Difference from GHG assessment	NA	5.09%	-0.48%

*The reduced annual fuel consumption by weight is based on the higher calorific value of the fuel used in NGERS Method 1. The reduction was calculated based upon the same amount of annual fuel consumption on an energy (Gj consumed) basis.

It is likely that the fuel characteristics used are based on the actual fuel used at the nearby Liddell and Bayswater power plants, which would be an appropriate assumption if the fuel suppliers have spare capacity to supply the Bayswater B coal fired option. Given that the fuel consumption is given to the nearest 100kt per annum, the 5% difference when using GES figures for the coal characteristics appears to lie within an acceptable range.

[4] AGO, 2006, *Generator Efficiency Standards: Technical Guidelines*, Department of Environment and Heritage

Using NGERS Method 1, the coal fired option would end up consuming less coal by weight to generate the same amount of electricity. This resulted in a minor net reduction in annual emissions from fuel consumption compared to the EA.

Gas fired option

The chemical properties of the gas option fuel have are not contained in the GHG assessment or the main body of the EA. Although not stated within the text of the EA, by using factors from NGERs Method 1 and the estimated annual fuel consumption, a figure was arrived at that closely resembled the annual emissions presented in the greenhouse gas assessment. This is shown in the table below.

Table 2 Quantification of emissions from fuel combustion - gas fired option

NGERS terminology	NGERS Method 2 Bayswater B GHG Assessment	NGERS Method 1
Quantity of fuel (Gj p.a)	112,500,000	112,500,000
Energy content (Gj/t)	51.24	NA
Fuel emission factor (kgCO2/Gj)	Not shown in EA	51.33
Emissions (tCO2e p.a)	5,771,000	5,774,625
Difference from GHG assessment	NA	0.03%

Capacity factor of plant

It is important that the capacity factor[5] used for calculating annual emissions is the maximum technically achievable by the power plant. This ensures that the calculations are based on the maximum amount of fuel being consumed; therefore the worst case annual emissions are quantified. Section 5.2.8 and 5.3.8 in the main body of the EA state that the technical assessments are based on an annual capacity factor for the gas and coal fired options is 92%.

Based on data published by the US Department of Energy[6] data and ACIL Tasman[11] the maximum annual capacity factor for Ultra Supercritical Coal would be around 85 to 90% of the installed capacity. Based on similar data published by the U.S. based National Renewable Energy Laboratory[7] Combine Cycle Gas Turbine capacity factor can be over 90% of the installed capacity. These published figures imply that the assumptions for maximum capacity factor are appropriate to estimate worst case scenario emissions from fuel combustion.

Proponent-owned transport emissions

Transport emissions from Proponent owned or operated vehicles in both the construction and operation phases of the project have been calculated based on a number of petrol fuelled vehicles (10 for USC option and 7 for CCGT option) travelling a maximum of 500km per week. This approach is appropriate, however there is little evidence provided to substantiate either estimate. In order to review the estimates Arup would require the

[5] The Energy Suppliers Association of Australia define capacity factor as Total Annual Generation as a percentage of Total Installed Capacity (MW) multiplied by the number of annual hours (8760). Capacity Factor is determined by several key characteristics of a power plant including the amount of time the plant is running over the year (assumed to be 100% in the EA), and the actual load the generating equipment is running (like a car engine, power plants can run at different outputs).
[6] National Energy Technology Laboratory, 2007, *Cost and Performance Baseline for Fossil Energy Plants*, U.S Department of Energy
[7] National Renewable Energy Laboratory, 2009, *Energy technology Costs and Performance Data*, available at http://www.nrel.gov/analysis/capfactor.html

average fuel consumption of the vehicles used in km travelled per kilolitres of petrol consumed. These emissions make up a tiny fraction of Scope 1 emissions and are considered by Arup to be immaterial to the assessment.

Arup considers that the calculation of estimates of Scope 1 emissions appear to be acceptable. However the calculations are not shown to an acceptable level of detail and therefore cannot be reviewed in depth. Although the GHG assessment has stated the calculation methodologies used there is very little evidence provided to that effect.

2.2.2 Scope 2 emissions

In the GHG assessment, scope 2 emissions from purchased electricity have been calculated to be 89 tCO_2e per annum.

This is based on the project consuming a maximum of 100MWh per year and using the NGERs emission factor for electricity use in NSW and the ACT (0.89tCO_2e/MWh). This approach is appropriate as the GHG assessment states that both options are planned to operate 365 days a year and this energy would only be used in a situation where all generation units were out of service at the same time.

Arup considers that the quantification of Scope 2 emissions is appropriately conservative and that Scope 2 emissions associated with the project are negligible.

2.2.3 Scope 3 emissions

Scope 3 emissions for the coal fired option are estimated to be 712,800 tCO_2e for construction and 299,800 tCO_2e per annum for the operational period. Scope 3 emissions for the gas fired option are estimated to be 286,600 tCO_2e for construction and 154,800 tCO_2e per annum for the operational period.

The GHG assessment explains that only Scope 3 emissions thought to be significant have been included in the greenhouse gas assessment. These significant activities include steel, concrete batching and combustion of transport fuels used in construction; fugitive emissions from fuel extraction and transport fuel in operation.

Construction materials

Emissions related to construction materials within the GHG assessment are shown in the table below.

For the purposes of embodied carbon calculations, Arup generally uses the Australian LCA database[8]. The database contains values for volumes of concrete and steel used in energy infrastructure as presented in below. These tables also present the values for embodied carbon in construction materials as presented in the GHG assessment for the two options for the proposed power plant and those estimated by the Mt Piper EA. The GHG assessment includes estimates for emissions from construction materials, but no estimated volumes of steel or concrete have been provided.

Table 3 Comparison of embodied greenhouse gas emissions in concrete and steel for coal fired power plants

Plant	2640 MW NSW black coal power plant	Bayswater B proposed 2000MW	Mt Piper proposed 2000MW coal fired

[8] The Australian LCA Database was initially developed as part of a joint project between the Centre for Design at RMIT and the Co-operative Research Centre for Waste Management and Pollution Control. Over the five years since its initial development data has been updated and new data added work undertaken at the Centre for Design and by other SimaPro users around Australia. The data includes fuels, electricity, transport, building and packaging materials, waste management and some data on agricultural production

		coal fired power plant	power plant
Source of Data	Australian LCA Database	Environmental Assessment	Environmental Assessment
Concrete (tonnes)	1,176,000	Not specified	46,244
Steel (tonnes)	194,000	Not specified	48,800
Total Embodied Carbon (tCO2 -e)	572,000	623,000	135,144
Embodied Carbon* (tCO2-e/MW)	217	312	68

*for comparison only, some equipment may not be scalable.

Table 4 Comparison of embodied greenhouse gas emissions in concrete and steel for gas fired power plants

Power Plant	85 MW gas fired power plant	Bayswater B proposed 2000MW gas fired power plant	Mt Piper proposed 2400MW gas fired power plant
Source of Data	Australian LCA Database	Environmental Assessment	Environmental Assessment
Concrete (tonnes)	33,236	Not specified	22,032
Steel (tonnes)	3,424	Not specified	12,200
Total Embodied Carbon (tCO_2 -e)	11,900	235,600	35,106
Embodied Carbon* (tCO_2-e/MW)	140	118	15

*for comparison only, some equipment may not be scalable.

The comparison shows that the Bayswater B GHG assessment estimates of embodied carbon are over the Australian LCA Database figures for the coal fired option and under the Australian LCA Database figures for the gas fired option. Despite the difference Arup considers that they are within a plausible margin given site specific requirements could alter many structural elements. Another reason for the slight differences between the gas fired options is that the Bayswater B Power Station is much bigger, meaning that the supporting infrastructure (roads, ancillary buildings, etc) would contribute a smaller proportion to the average embodied carbon (per MW).

Construction fuel usage

The GHG assessment has estimated transport emissions arising from non-Proponent owned vehicles during construction as 89,800 tCO_2e for the coal fired option and 51,000 tCO_2e for the gas fired option.

There is little evidence provided to substantiate estimates for either the coal fired or gas fired options. In order to review the estimates Arup would require:

- Total distance travelled by non-Proponent vehicles per year;
- Average fuel consumption by fuel type (i.e. diesel or petrol) of the vehicles used in km travelled per kilolitres consumed.

It is not stated whether or not these estimates include the fuel usage that would be associated with construction plant and equipment (e.g. diesel generators, forklifts, cranes, excavators etc), though the label of these emissions as *"transport emissions"* suggests they do not. This is a potentially significant source (in terms of the construction period) of emissions that does not appear to have been quantified by the GHG assessment.

Fuel extraction, processing and supply

The GHG assessment estimates that fugitive emissions from fuel extraction are 281,200 tCO_2e per annum for the coal fired option and 147,600 tCO_2e per annum for the gas fired option. The GHG assessment estimates that emissions from transporting fuel to the site are 13,200 tCO_2e per annum for the coal fired option and 6,100 tCO_2e per annum for the gas fired option.

The following additional information would be required to fully review the fugitive emissions and fuel transport emissions calculations:

- Description of the type of coal mining (underground or open cut) which would determine the generic fugitive emission figure to use;
- The distance required to transport the coal by train which would determine coal transport emissions;
- Queensland to the Hunter Gas Pipeline length and yearly quantities of fuel transported which would determine gas transport emissions.

Assuming that the coal is supplied by open cut mines, the figures for fugitive emissions seem reasonable as shown in the table below.

Table 5 Quantification of fugitive emissions - coal fired option

NGERS terminology	Bayswater B GHG Assessment	NGERS Method 1
Quantity of fuel extracted (t p.a)	6,300,000	6,300,000
Fuel emission factor (kgCO2e/kg)	Not shown in EA	0.045
Emissions (tCO2e p.a)	281,200	283,500
Difference from GHG assessment	NA	0.82%

The table below shows a comparison of the quantification of fugitive emissions for the gas fired option.

Table 6 Quantification of fugitive emissions - gas fired option

NGERS terminology	Bayswater B GHG Assessment	NGERS Method 1
Quantity of fuel (Gj p.a)	112,500,000	112,500,000
Calorific value (Gj/t)	51.24	51.24
Quantity of fuel (t p.a)	Not shown	2,195,550
Fuel emission factor (tCO2e/t)	Not shown	0.0012
Emissions (tCO2e p.a)	147,600	135,000
Difference from GHG assessment	NA	-8.54%

Despite the lack of calculations shown in the GHG assessment, the quantification of fugitive emissions from fuel extraction appears to be within an expected range. As stated earlier, the transport fuel emissions are not possible to review given the limited data provided. Although the GHG assessment had quantified fugitive emissions and fuel transport emissions, it has not quantified the total emissions associated with the extraction, processing and supply of fuel.

Scope 3 emissions from the energy use in fuel extraction and processing are not included in the GHG assessment, even though they would be likely to be more significant than other emissions that are included (i.e. transport emissions from non-Proponent owned vehicles). Fuel usage in coal extraction is estimated to make up 12.1% of upstream emissions associated with the use of coal[9]. There are other Scope 3 emissions related to the extraction, processing and supply of fuel that have not been quantified, extraction energy use is just one of several.

In lieu of complete data from the GHG assessment and the main body of the EA, an alternative methodology has been applied by Arup to quantify Scope 3 emissions from the extraction, process and supply of fuel. The emissions could be quantified using generic Scope 3 emission factors provided by NGA Factors that encompass the fuel extraction, fugitive emissions, energy use in supply and supply losses in one factor for consumption of each fuel type. Applying these factors to the fuel quantities stated in the main body of the EA would give substantially larger estimates of Scope 3 emissions than those in the GHG assessment, as shown below:

Table 7 Scope 3 emissions according to NGA Factors methodology

Scope 3 emissions from the extraction, processing and supply of fuel	Coal fired option		Gas fired option	
	GHG assessment	NGA Factors	GHG assessment	NGA Factors
Fuel consumption (Mt p.a.)	6.3	6.3	NA	NA
Energy content (Gj/t)	21.76	21.76	NA	NA
Fuel consumption (Pj p.a)	137.1	137.1	112.5	112.5
Scope 3 emission factor[10] (kgCO2e/Gj)	Not given	4.6	Not given	15.7
Fuel related Scope 3 emissions (tCO2e p.a.)	294,400	630,605	153,700	1,766,250
Difference from GHG assessment	NA	114.20%	NA	1049.15%

Arup assumes the large difference between the scope 3 emissions in the GHG assessment and in the NGA Factor approach is in part due to fuel supply chain specific to the Project. However a significant proportion (especially for the gas-fired option) is likely to be due to the omission of several emission causing activities from the GHG assessment.

Arup notes that with an expected increase in the supply of coal seam methane in NSW, the emission factors used for both Scope 3 emissions and fugitive emissions for gas consumption in NSW are likely to change. The quantum of this change is uncertain as coal seam methane may be more energy intensive to process than natural gas, however it will be supplied from locations closer to Bayswater which is likely to reduce fugitive emissions. Arup considers that the best approach is to use current figures given the uncertainty of the nature of the future NSW gas supply.

Non-Proponent owned transport

The GHG assessment estimates the quantity of emissions arising from non-proponent owned vehicles in operation as 5,400 tCO_2e for the coal fired option and 1,100 tCO_2e for the gas fired option.

[9] Aus LCA Database, RMIT Centre for Design, 2004, *Black coal production for the year 2001-02*. Data collected from the National Greenhouse Gas Inventory on coal production and fuel use.
[10] Department of Climate Change, 2009, *National Greenhouse Accounts Factors 2009,* taken from Table 36: Scope 3 emission factors – solid fuels and certain coal based products and Table 37: Scope 3 emission factors – gaseous fuels

The figures differ between the coal and gas fired options primarily because of the use of trucks to transport waste products (i.e. ash) offsite. However there is little evidence provided to substantiate either estimate. In order to review the estimates Arup would require:

- Total distance travelled by non-Proponent per year;
- Average fuel consumption by fuel type (i.e. diesel or petrol) of the vehicles used in km travelled per kilolitres consumed.

The order of magnitude of the estimates in the GHG assessment indicate that the emissions from non-proponent owned vehicles are unlikely to be material to the overall environmental impact of the project.

Emissions from fuel combustion waste – coal fired option

There could also be some consideration of the downstream use of fly ash, which could give the Bayswater B project Scope 3 credits. Fly ash can be used as a cement replacement, in effect offsetting the emissions associated with cement production. In this way, a Scope 3 emission credit may be able to be attributed to the generator as a result of the reduced need for cement production within the wider economy.

Arup considers that it is likely that the most significant source of Scope 3 emissions over the whole of project life would be from fuel extraction, processing and supply. Arup considers that the approach adopted by the GHG assessment for the quantification of fuel extraction, processing and supply is unacceptable and is likely to have resulted in a significant underestimate.

Using Scope 3 emission factors from NGA Factors, this underestimate appears to be in the order of 100% for the coal fired option and 1000% for the gas fired option.

Arup considers that there are several sources of Scope 3 emissions for the construction period which have not been included within the assessment including fuel usage by construction plant and equipment. As a result, total construction period Scope 3 emissions are likely to be underestimated. However, in comparison to the emissions likely to be generated over the 30 year period of operation, construction related emissions are not likely to be material to the assessment.

2.2.4 Total annual emissions

The total emissions for the coal fired option were 12,428,200 tCO_2e per annum in operation and 712,800 tCO_2e in construction. The total emissions for the gas fired option were 5,918,600 tCO_2e per annum in operation and 286,860 tCO_2e in construction.

In calculating the total anticipated emissions for the project, the GHG assessment has included emission categories that make a significant contribution to greenhouse gas emissions (fuel combustion). This approach is reasonable, as the emissions below this figure likely to be immaterial to the project as a whole.

As stated above, the Scope 3 emissions quantified in the GHG assessment are likely to be a large underestimate, so it is likely that the annual operational emissions would increase. However, it has become an industry standard to report Scope 1 and 2 emissions only as it is difficult to prove any Scope 3 emissions would have been avoided without the Project.

Arup considers that the quantification of total construction and annual operational greenhouse gas emissions includes the most significant emissions. The GHG assessment could justifiably revise its annual emissions to include Scope 1 and 2 emissions only.

3 Comparison of predicted emissions intensity and thermal efficiency

3.1 Calculation of thermal efficiency and emissions intensity

The emissions intensities in Section 10.3.3 of the GHG assessment were calculated based NGERs Method 2 methodology, whereas in Section 10.3.1 the GGAS methodology (which includes other emissions) was used for a comparison to the NSW pool coefficient intensity. The difference this makes is between 0.840tCO_2e/MWh (GGAS) to 0.817tCO_2e/MWh (NGERS) for the coal option and 0.398tCO_2e/MWh (GGAS) to 0.369tCO_2e/MWh (NGERS) for the gas option.

Calculations behind these thermal efficiencies and emission intensities are not shown within the GHG assessment or the main body of the EA; the results seem reasonable based on published data[11,6,12] on the thermal efficiencies of supercritical coal[13] and fuel properties stated in sections 5.2.8 and 5.3.8 of the main body of the EA.

Fuel characteristics

NGERs Method 2 methodology for calculating emissions from combustion of fuels (solid fuels Division 2.2.3, gaseous fuels Division 2.3.2)[14] is based upon the properties of the specific fuel to be used, established over a lengthy sampling period. As stated earlier in 2.2.1 Scope 1 emissions, the chemical analysis of the fuels required for a full review of the emissions from fuel combustion is not present in the GHG assessment or the main body of the EA, though the quantification of annual emissions from fuel combustion (and therefore likely the emissions intensity) was within an acceptable range based on published data[4].

Capacity factor

For emissions intensity calculations the capacity factor should be based on typical operations, not on a maximum power output (which should be used to calculate worst case annual emissions). As discussed earlier, the main body of the EA assumes that the generator is running at 92% capacity factor and states that this assumption is used in all of the technical assessments. This implies that the same capacity factor is used for both the worst case annual emissions and the typical emissions intensity of the electricity generated. Arup has shown this assumption is appropriately conservative for the calculation of worst case annual emissions; therefore it is likely to underestimate the typical emissions intensity. As an example, the Mt Piper EA assumes that the power plant is operating at a capacity factor of 80% in typical operations.

The emissions intensity and thermal efficiency for the existing Liddell and Bayswater plants are based on actual activity (typical capacity factors), while the proposed coal and gas fired options are assumed to be based on a maximum capacity factor. The existing plants are far lower in efficiency, and are presented as worst practice. Altering the capacity factor to

[11] ACIL Tasman, 2009, *Fuel resource, new entry and generation costs in the NEM*, prepared for the Interregional Planning Committee
[12] Massachusetts Institute of Technology, 2007, *The Future of Coal: Options for a Carbon-Constrained World*, MIT
[13] NOTE: The definitions of Ultra-Supercritical (USC) and Supercritical Coal (SC) are somewhat blurred. Both operate at temperatures and pressures above the critical point for steam. According to a report by numerous academics at MIT (above), while operating at a steam cycle above 565°C and pressures up to 32MPa is considered ultra supercritical (making Bayswater B coal fired option USC), supercritical coal thermal efficiencies range from 37% to 40% (making Bayswater B SC). Thermal efficiency figures calculated by ACIL Tasman (above) suggest that in Australia SC plants would have thermal efficiencies of 40.0% while USC plants would have thermal of 43% as sent out (the same figure is stated in the MIT report). However the MIT report states that current state of the art SC technology involved pressures of 24.3MPa, while the Bayswater B plant is proposed to operate at 28.5MPa.
[14] National Greenhouse and Energy Reporting (Measurement) Determination 2008 under subsection 10(3) of the National Greenhouse and Energy Reporting Act 2007

represent typical operations of the hypothetical plants is unlikely to alter any conclusion when determining best achievable practice. However the use of a technical maximum capacity factor to calculate emissions intensity may distort the comparison with the current NSW average emission intensity, which is based on actual activity (typical capacity factors).

Arup considers that the methodology for the calculation of thermal efficiency and emissions intensity is appropriate for comparison to best achievable practice. However the use of a very high capacity factor for comparison to the NSW average is likely to underestimate the emissions intensity which would be achieved in actual practice and is therefore unacceptable.

3.2 Comparison Against Best Achievable Practice

Section 10.3.3 of the GHG assessment compares the estimated thermal efficiency and emissions intensity of the gas and coal fired options against:

- A wet cooled CCGT plant;
- An H class CCGT plant;
- Existing power plants at Liddell and Bayswater (both of which are wet cooled subcritical coal technology);
- A wet cooled USC plant;
- An indicative Northern European USC, wet cooled power plant; and,
- A theoretical high efficiency USC plant design.

The EA does not look at other gas or coal fired technologies including open-cycle gas turbines or integrated gasification combined cycle (coal). This is acceptable as Ultra Supercritical Coal (USC) and Combined Cycle Gas Turbine (CCGT) technologies have been recognised as best practice for their respective fuels for base load generation[15].

The GHG assessment's analysis identifies best achievable practice for coal fired power, and best achievable practice for gas fired power. The Department of Planning has confirmed that the comparison against best achievable practice should be specific to the fuel type[16].

3.2.1 Gas fired power plants

Of the gas fired power plants, the technology with the highest thermal efficiency and lowest emissions intensity was CCGT with wet cooling followed by H class CCGT with air cooling and finally F class with air cooling (as proposed in the Bayswater B gas fired option).

Wet Cooling –gas fired

The GHG assessment states that the wet cooling *"option is not presently available for Bayswater B based on current water allocations"*. The wet cooling options are therefore considered to be unachievable at the Bayswater B site.

H class CCGT

The GHG assessment has not quantified the thermal efficiencies or emissions that are achievable at the Bayswater B site with an H class CCGT. GE and Siemens H class turbines are expected to have efficiencies of up to 60% with wet cooling[17,18] (as generated), as opposed to F class which would have 56% with wet cooling (as generated). The EA

[15] Owen, A, 2007, *Inquiry into Electricity Supply Within the State (Owen Inquiry),* NSW Government
[16] Personal Communications, Dinuka McKenzie (DoP), 7/10/2009, email entitled *RE: Clarification* to Peter Rand (Arup)
[17] http://www.gepower.com/prod_serv/products/tech_docs/en/downloads/ger3935b.pdf
[18] http://www.powergeneration.siemens.com/NR/rdonlyres/E3625D40-53C4-4453-A81D-B71A5C04CCB8/0/204_090818_Imagebr_8000H_Gasturbine_US.pdf

states that the benefits of H class over F class turbines with dry cooling would be marginal when the system is air cooled but does not quantify the difference. The Mt Piper EA does quantify this difference in air cooled CCGT turbines as shown in the table below.

Table 8 Mt Piper EA gas turbine analysis[19]

CCGT Model	GT26	9 FB	701 F	4000F	9H	701 G
Supplier	Alstom	GE	MHI	Siemens	GE	MHI
Number of Units	6	6	5	6	5	5
Nominal Net Capacity (MW)	2,193	2,283	1,997	2,171	2,164	2,142
Net Efficiency (%, HHV)	51.5%	51.8%	51.3%	51.6%	52.9%	52.4%
Net Heat Rate (kJ/kWh, HHV)	6,990	6,940	7,020	6,980	6,810	6,880

The information from the Mt Piper EA indicates that an air cooled H class power plant (9H in the table above) would have a thermal efficiency of 52.9% compared to an F class power plant (9FB, 701 F and 4000F in the table above) which would have a thermal efficiency between 51.3% and 51.8%.

As the GHG assessment states that an H class power plant is achievable, the proposed gas fired option (F class) does not constitute best achievable practice.

Arup considers that the Bayswater B gas fired option is not the best achievable practice for emission intensity and thermal efficiency in gas fired generation. An H class based CCGT is achievable and has a higher thermal efficiency and lower emissions intensity.

3.2.2 Coal fired power plants

Of the coal fired power plants analysed in the GHG assessment, the Northern European USC plant had the highest thermal efficiency and lowest emissions intensity, followed by a wet cooled USC plant, a theoretical high efficiency USC design, the Bayswater B USC option and finally the existing power plants.

Northern European USC

The indicative Northern European plant's thermal efficiency and emissions intensity were calculated based on a cooler ambient temperature and lower cooling water temperatures that can be associated with the cooler climate of high latitude regions like Northern Europe. It is reasonable to assume that these conditions will not be present at the Bayswater B site and are therefore unachievable.

Wet Cooling –coal fired

The GHG assessment states that the wet cooling *"option is not presently available for Bayswater B based on current water allocations"*. The wet cooling options are therefore considered to be unachievable at the Bayswater B site.

Theoretical high efficiency thermal design – coal fired option

Section 10.4.1 of the GHG assessment shows analysis of the theoretical high efficiency thermal plant for the coal fired option which shows improvements of up to 1% in thermal

[19] SKM, 2009, *Mt Piper Power Station Extension: Environmental Assessment,* Table 3-2

efficiency and a 2% decrease in emissions intensity. The cost for this technology is estimated to be $120/tCO_2e reduction.

Although, the detailed analysis behind both the efficiency improvement and the financial costs are not shown, the GHG assessment concludes that*: "this option is not considered commercially viable"*. There is no information presented on how this figure was calculated (i.e. life of plant, weighted average cost of capital, total emissions offset etc), and it is unclear if the cost of carbon reduction includes income from the additional electricity produced by the upgraded plant.

The theoretical high efficiency thermal design is identified as technically achievable at the Bayswater B site. The evidence to suggest that it is not commercially viable is not shown adequately.

Arup considers that the Bayswater B coal fired option <u>is not the best achievable practice</u> for emission intensity and thermal efficiency in coal fired generation. The GHG assessment details the different power plant equipment and layout that could be achieved at the Bayswater B site to increase thermal efficiency and decrease emissions intensity.

3.3 Comparison of thermal efficiency and emission intensity against current NSW average

The Department of Planning has confirmed that the comparison to the current NSW average for the activity should be made to electricity generation in general[16]. This implies that the comparison is to consider all forms of electricity generation including that sourced from peaking power stations and renewable energy power stations.

3.3.1 NSW average thermal efficiency

The analysis contained in the GHG assessment compares the two option's thermal efficiencies and emission intensities with the existing Macquarie Generation power plants but not with any other existing plants. The following table shows the existing or soon to be built major power plants in NSW according to an ACIL Tasman report from April 2009[11].

Table 9 ACIL Tasman analysis of fossil fuel power plants in NSW

Generator	Type	Fuel	Size (MW)	Thermal efficiency HHV (%) sent-out*
Bayswater	Steam turbine	Black coal	2,640	35.90%
Colongra	OCGT	Natural gas	664	32.00%
Eraring	Steam turbine	Black coal	2,640	35.40%
Hunter Valley GT	OCGT	Fuel oil	50	28.00%
Liddell	Steam turbine	Black coal	2,000	33.80%
Mt Piper	Steam turbine	Black coal	1,320	37.00%
Munmorah	Steam turbine	Black coal	600	30.80%
Redbank	Steam turbine	Black coal	150	29.30%
Smithfield	CCGT/Cogen	Natural gas	176	41.00%
Tallawarra	CCGT	Natural gas	435	50.00%
Uranquinty	OCGT	Natural gas	664	32.00%
Vales Point B	Steam turbine	Black coal	1,320	35.40%

Wallerawang C	Steam turbine	Black coal	1,000	33.10%

*The figures are slightly different to those contained within the EA for the existing Bayswater and Liddell power stations, indicating a different methodology has been used by ACIL Tasman to calculate the efficiencies and intensities.

No comparison with the NSW average thermal efficiency is contained in the GHG assessment or the main body of the EA. An indicative average could have been calculated by determining the average thermal efficiency by generational capacity (so that efficiencies of larger plants are more heavily weighted against smaller plants). For indicative purposes only, if the values in the table above were used this average would be around 35%.

Although there is no comparison within the GHG assessment, it is highly likely that both coal and gas options have higher thermal efficiencies than the current NSW average thermal efficiency.

3.3.2 NSW average emissions intensity

The current NSW average emissions intensity could be calculated using various methodologies including:

- The Greenhouse Gas Abatement Scheme pool co-efficient for 2009;
- The NGA Factors NSW electricity emissions intensity for 2008 altered to take into account transmission losses;
- A calculation based on electricity generators currently operating in NSW, their emissions intensity and annual electricity generation.

GGAS pool co-efficient

The GHG assessment compares the predicted emissions intensity of the Bayswater B options against the NSW Pool Co-efficient for 2009. The emissions intensities for the Bayswater B options were recalculated with the GGAS methodology (which differ from the NGERs Methodology) to give a like for like comparison. Using this methodology the GHG assessment shows that both options for the Bayswater B project are below the current published NSW pool coefficient. However, Arup does not consider that the NSW pool coefficient accurately represents the current average emissions intensity for electricity generation in NSW as it is not based on all of the electricity generator in NSW (as detailed below).

Section 10.1.1 of the GHG assessment states that: *"DECCW has confirmed that GGAS is the standard, accepted and most transparent benchmarking available in NSW",* however this is not stated within the DECCW Stakeholder letter and no evidence of this recommendation is provided in the GHG assessment or the main body of the EA. The GGAS pool coefficient is used for the purpose of calculating New South Wales Greenhouse Abatement Certificates (NGACs) and provides an *indicator* of the average emission intensity of the electricity sourced from the electricity grid in NSW.

The pool coefficient is in fact the weighted average of the emission intensities of existing Category B generators (as defined by the GGAS scheme). The Category B generators are represented by 8 existing steam/coal type power plants, one existing gas turbine power plant and thirteen existing hydro electric plants. Any newer generators that have come on line or that will come on line since the inception of the Scheme in NSW in 2003 are not deemed to be Category B Generators and therefore do not contribute to the pool coefficient[20].

[20] http://www.greenhousegas.nsw.gov.au/acp/generation.asp

The NSW Pool Co-efficient does not include electricity sourced from gas or any other fossil fuel fired power plants, wind farms or biomass cogeneration plants that are currently in operation in NSW. The comparison between the NSW Pool Co-efficient from 2009 is of limited value as conceptually it is comparing current power plant technology with power plants built before the GGAS scheme was introduced, not the current NSW average.

Arup considers that use of the NSW pool co-efficient is not an acceptable representation of the current NSW average emissions intensity of electricity generation for comparative purposes.

NGA Factors

NGA Factors provide an emissions intensity factor for the consumption of electricity in NSW. In the most recent NGA Factors this is determined as 0.89 t CO_2-e per MWh. This factor is based on energy delivered to consumers *excluding* transmission and distribution losses and therefore is equivalent in emission intensity per unit of energy sent out from generators. The NGA Factors value for emission intensity of electricity delivered in NSW and can therefore be considered representative of the average emission intensity for electricity sent out in NSW. This is further explained in the NGER technical guidelines below:

> *The emission factor for scope 2 is defined in terms of energy sent out on the grid rather than energy delivered because this effectively ensures that end users of electricity are allocated only the scope 2 emissions attributable to the electricity they consume and not the scope 2 emissions attributable to electricity lost in transmission and distribution. The latter are allocated to the transmission and distribution network.*

The methodology for determining this factor is based on the following equation

$$\frac{a+b-c}{A+B-C}$$

where:

a = total emissions from power generation in NSW;

b = pro-rata share of power generation emissions incurred in other States from which electricity is imported to NSW, as determined from net energy purchases;

c = pro rata share of power generation emissions incurred in NSW from which electricity is exported to other states, as determined from net energy purchases.

d = the total electricity consumed within NSW.

A = total energy generated (sent out) in NSW;

B = energy imported to NSW from other states, as determined from net energy purchases;

C = energy exported to NSW from other states, as determined from net energy purchases.

There are several issues in using the NGA Factor as to represent the NSW current average emission intensity for the purposes of comparing the project.

The NGA Factor is based on national emissions data which by the time it is published is already out of date. For example, the most recent NGA Factor published in 2009 is based on emissions data from 2007 at the latest. In addition, the NGA Factor is based on a rolling 3 year average. Both of these factors imply some time lag in the impact of renewable and low carbon generation technologies which have come on line since 2005 or plants which will come on line in the near future. Secondly the factor is sensitive to emission intensities of generation in Queensland and Victoria from where NSW imports electricity.

Therefore, it is considered that while the NGA Factors is indicative of the current NSW average emission intensity, it may not be appropriate for direct comparison. However, it is useful in providing an estimate of current emissions intensities and in demonstrating the extent to which the GGAS pool coefficient is likely to represent an overestimate.

Arup considers that the NGA Factors emission intensity is indicative of the average NSW emission intensity in 2007 and may therefore be useful in providing an estimate of current emissions intensities.

Operating NSW power plants

The most accurate benchmark for NSW current emission intensity can be determined through an analysis of current operating NSW plants using the following formula:

$$a/E$$

Where

a = total emissions from power generation in NSW for 2008/2009;

E = the total electricity generated within NSW for 2008/2009.

This information can be obtained from an analysis of existing power plants and their generation and fuel sources for the most recent financial year. However this sort of analysis requires access to detailed figures relating to installed capacity, capacity factor, thermal efficiency and total sent out generation for all operating power plants in NSW and is difficult to undertake without access to commercial information.

Alternatively, aggregated published figures for total NSW stationary energy emissions and total NSW electricity generation may be used.

Potential sources of the figure for total emissions from electricity generation in NSW can be found from the National Greenhouse Gas Inventory (NGGI) or from individual energy generators National Greenhouse and Energy Reporting Scheme (NGERS) reports that would show the emissions for the individual power stations. There are problems with both of these sources. The latest data available from NGGI is from 2007 so it is not a precise reflection of current NSW stationary energy emissions. To date, NGERS reports have not been made public, so this option is not currently available.

Potential sources of the figure for total electricity generated within NSW are from yearly aggregated data from the Australian Energy Market Operator (AEMO), or published figures from the Australian Bureau of Resource Economics (ABARE) or the Energy Supply Association of Australia (ESAA). AEMO publishes aggregated monthly figures for price and demand but no aggregated data figures for electricity dispatched to the grid; these come in half hourly figures, so calculating the total electricity dispatched over a year would be complex.

ABARE have published a rounded figure for electricity generation in NSW[21] for the financial year 2007-2008. ESAA have published more detailed numbers for the financial year 2007-2008[22]. Unfortunately the ESAA and ABARE figures are not aligned and there is a level of uncertainty over which is more accurate given the various exclusions from each. Also these numbers do not correspond to the NGGI figure above as GHG emissions are quantified on a calendar year basis to align with Kyoto Protocol reporting requirements.

[21] ABARE, 2009, Energy in Australia 2009, Department of Resources, Energy and Tourism, pp22
[22] ESAA, 2009, *Electricity GAS Australia 2009*

A report by the Climate Group[23] has aggregated the AEMO (formerly NEMMCO) data and used emission factors for generators as published in an ACIL Tasman report[11]. As the Climate Group's analysis is reliant on emission factors for individual power plants based on historical trends, and not on actual annual GHG emissions, its results should be taken as indicative only. The Climate Group's analysis is shown below:

Table 10 NSW Emissions and generation in 2008 (The Climate Group)

Sector	Emissions (million tonnes CO_2e)	Generation (MWh)	Generation growth on 2007
Coal-fired generation	66698	71,053,000	0.70%
Gas-fired generation	0.619	1,140,000	11.30%
Liquid fuel-fired generation (i.e. Diesel/ distillate)	380	437	136.90%
Renewable generation	0	4,354,000	2.10%

These figures would suggest an average emissions intensity of 0.876tCO_2e/MWh for electricity generation in NSW in 2008, although the appropriateness of comparison to this figure is also uncertain. It is unclear whether the figures for generation are as generated or as sent out, if the figures are as generated the actual average emissions intensity would be higher. Judging by the difference between as generated (72870.9 GWh) and as sent out (68549.5 GWh) figures for 2007-2008 published by the ESAA, the scale of this underestimate could be in the realms of 5% or 6%.

However, these figures include Scope 3 emissions from fuel extraction, processing and supply, implying that an emissions intensity that only includes Scope 1 emissions would be lower than the figure above. If all generation in NSW was from coal fired power stations this would result in an overestimate in the realms of 3% or 4%.

Arup considers that the average emissions intensity for electricity generation in NSW is likely to be relatively close to the Climate Group's figure if it was based on electricity as generated. If the Climate Group figures are based on as sent out basis they could overestimate the average emissions intensity for electricity generation in NSW.

Current and future NSW average emissions intensity

All three of the proposed methodologies for calculating the average emissions intensity for electricity generation in NSW have a similar problem; they are based on historical data and therefore cannot reflect the actual current average. The following table shows the additional capacity at an advanced planning stage (likely to be built in the next few years) or already installed in NSW:

[23] The Climate Group, 2009, *Greenhouse Indicator Series: Australian Electricity Generation Report 2008*, available at http://www.theclimategroup.org/assets/resources/AUSTRALIAN_ELECTRICITY_GENERATION_REPORT_2008_-_JULY_2009_-_The_Climate_Group_-_July_2009.pdf

Table 11 Additional energy generation in NSW[24]

Additional electricity generation in NSW, post 2008	Additional capacity (MW)
CCGT planned	1220
CCGT (already built)	400
Sub critical coal planned	240
Open Cycle Gas Turbine (OCGT) planned	3500
OCGT (already built)	640
Wind planned	2750
Biomass steam (already built)	60

There are several small and medium scale projects that are already in operation but have not yet contributed to any of the annual emissions or electricity generation figures publically available. These power plants are either gas fired or renewable in nature so they will have decreased the current NSW average emissions intensity from historic figures.

The vast majority of the planned projects (all but two) will have emissions intensities significantly lower than the current NSW average, implying that the average emission intensity will be reduced further once they are in operation.

Arup considers that the GHG assessment is likely to have under estimated average annual emission intensities of both technology options as the calculations assume a very high capacity factor which would result in an average annual thermal efficiency similar to design efficiency and a lower emissions intensity.

Notwithstanding, the annual average emissions intensity of the coal fired option is likely to be no more than the current average emissions intensity of electricity generation in NSW. By the time the coal fired option would be built in 2015, the average NSW emissions intensity is likely to have reduced such that there is potential for the coal fired option to have an emissions intensity greater than the average NSW emissions intensity at that time.

The emissions intensity of the gas fired option is likely to be significantly less than the NSW average emission intensity at current levels and into the foreseeable future.

3.4 Comparison against national emissions

The GHG assessment compares the significant annual Scope 1 and Scope 3 emissions of the two Bayswater B options against a future scenario of total national greenhouse gas emissions over the life of the project. In the GHG assessment's analysis, the coal fired option is responsible for 2.02% of total national emissions in 2015 and 1.28% of total national emissions by the year 2044; the gas fired option is responsible for 0.96% of total national emissions in 2015 and 0.61% of total national emissions in 2044.

The comparison assumes a 1.6% increase in national GHG emissions per year (Section 10.3.2). The rationale for this growth in emissions is that it represents a "worst case scenario" for emissions growth based on historical trends. This means that in 2044 (the last year analysed) the percentage of national emissions is reduced as national emissions grow. While this represents a "worst case scenario" for total annual national emissions, it represents a best case scenario for the project.

In Arup's view, the more realistic "worst case scenario" for the project is if the Federal Government passes the CPRS into law as proposed, meaning national emissions will be

[24] ABARE, 2009, *Electricity generation projects: April 2009 listings*, and the spreadsheet data from http://www.abare.gov.au/publications_html/energy/energy_09/EG09_AprListing.xls

reduced over time because of a price on greenhouse gas emissions. If the CPRS is passed into law and predicted emission reductions eventuate, both the coal fired and gas fired options will emit a significantly larger proportion of national emissions by 2044 than in 2015 (see below).

According to the estimates of future National Emissions published by the Treasury[25] the figures quoted in the GHG assessment would result in a significantly different contribution to national emissions compared to those stated in the GHG assessment. A comparison between the gas fired and coal fired annual emissions to the total annual national emissions forecast under the CPRS 15 (15% reduction target by 2020, 60% by 2050) scenario is shown below:

Table 12 Bayswater B contribution to total annual national emissions under the CPRS 15 scenario

Predicted Emissions item	GHG Emissions	% of National emissions
Total Annual National Emissions 2015 - CPRS 15[26]	530,760,000	100%
Bayswater B coal fired option 2015	12,428,200	2.29%
Bayswater B gas fired option 2015	5,918,600	1.09%
Total Annual National Emissions 2044 - CPRS 15[26]	242,620,000	100%
Bayswater B coal fired option 2044	12,428,200	5.01%
Bayswater B gas fired option 2044	5,918,600	2.38%
Total cumulative National Emissions 2015-2044 – CPRS 15[26]	10,869,980,000	100%
Bayswater B coal fired option cumulative 2015 - 2044	364,410,000	3.35%
Bayswater B gas fired option cumulative 2015 - 2044	173,130,000	1.59%

The above scenario is based on the CPRS 15 projections by the Treasury. Within these projections is the assumption that Australia's emissions reduction target for 2050 is 60% below 2000 levels. If this target were increased by the Federal Government the proportion of national emissions attributed to the Project would increase further.

The scale of emissions that could be attributed to the Bayswater B project is so large the Project would potentially have an interaction with several Federal Government policies. These include the review of the Environmental Protection and Biodiversity Conservation Act 1999 and the medium term emissions reduction targets.

3.4.1 Comparison against Greenhouse Trigger under Review of the Environment Protection and Biodiversity Conservation Act 1999

The Federal Government Environmental Protection and Biodiversity Conservation Act 1999 is currently under independent review. The review's interim report[27] was released in June this year. The Hawke report (the final report) is expected to be given to the Minister for the Environment, Heritage and the Arts by the 31st of October, 2009. The interim report includes a discussion points about incorporating climate change mitigation under the Act, including

[25] Treasury, 2008, *Australia's Low Pollution Future: The Economics of Climate Change Mitigation*
[26] http://www.treasury.gov.au/lowpollutionfuture/spreadsheets/report_charts/Executive_Summary/Chart%201%20-%20Five%20pathways%20for%20Australian%20emissions%20and%20GNP.xls
[27] Department of the Environment, Water, Heritage and the Arts, 2009, *Independent Review of the Environment Protection and Biodiversity Conservation Act 1999: Interim Report*, available at http://www.environment.gov.au/epbc/review/publications/interim-report.html

GHG emissions trigger that, if tripped, would mean projects would need to be referred to the Commonwealth Government for assessment under the Act.

The trigger points discussed in the interim report come from a submission from Dr Chris McGrath, the Australian Greens and the Australian Labor Party and range from 25,000 to 500,000 tonnes of carbon dioxide equivalent per year. If a trigger point in this range (or even significantly higher) were to be recommended by the final report, and legislated by the Federal Government, the Bayswater B Power Station Project would trigger the EPBC Act and would therefore require approval from the Federal Government. The annual emissions for both options are more than ten times the higher proposed trigger levels indicating that the project could be considered nationally significant in terms of greenhouse gas emissions.

3.4.2 Comparison against Australia's emissions reduction targets

The Federal Government has made a commitment to reducing Australia's GHG emissions by 60% by 2050 on 2000 levels. Interim targets have not yet been finalised but the Federal Government has indicated that targets will be a minimum of 5% and up to a maximum of 25% reduction on 2000 levels by 2020. To achieve the targets will require abatement of between 138 and 249 $MtCO_2$-e per year compared to business as usual by 2020[28], while the project will be between 5.9 and 12.4 $MtCO_2$-e per year according to the GHG assessment.

The coal fired option will lock coal fired generation technology into the Australian electricity supply for around 30 years. This is likely to make achieving any of the Australian GHG emissions reductions targets harder, and increase the costs of Australian Emission Units to the wider community.

Arup considers that comparison against currently national emissions in the GHG assessment does not represent the worst case scenario for the project and is not acceptable. The worst case national emissions scenario for the project would be a steep reduction in GHG emissions over time.

Arup considers the most appropriate projection of national emissions for comparison is the Treasury's CPRS 15 scenario (CPRS is passed with a 15% reduction on 200 levels target by 2020). The greenhouse gas emissions as outlined in the GHG assessment would represent approximately 3.4% (coal fired option) or 1.6% (gas fired option) of national emissions over the lifetime of the project based on the CPRS 15 projections.

Further, Arup considers that the total emissions from the project are nationally significant based on the indicative triggers in the Review of the EPBC Act. The emissions are also considered significant in terms of increasing the overall abatement which must be achieved for Australia to meet its emission reduction target.

[28] Department of Climate Change 2009, Tracking to Kyoto and Beyond: Australia's Greenhouse Emissions Trends: 1990 to 2008–2012 and 2020

4 Evaluation of measures to reduce and/ or offset the greenhouse gas emissions

The GHG assessment and the main body of the EA both refer to several measures to reduce and/or offset GHG emissions. The focus is on measures that will reduce operational emissions, which is reasonable given the substantial proportion of total project GHG emissions. However, measures that could be implemented during construction including cement replacement and recycled steel content would still result in considerable reductions of GHG emissions given the scale of the project.

The following is a review of the GHG assessment's analysis of various emission reduction and offsetting measures and the trigger points identified for their implementation.

4.1 Trigger points for mitigation measures

The GHG assessment outlines a list of triggers that would determine investment in emissions reductions and offsetting. The GHG assessment states that the opportunities for mitigation would be reviewed at least once every two years.

The GHG assessment states that the mitigation measures to be reviewed are:

- *"Emissions reduction and carbon capture technologies available or in development "* (From the GHG assessment, Arup assumes this includes renewable energy augmentation)
- *"Technologies and opportunities to transport and store captured* CO_2*"*
- *"Opportunities to invest in carbon offset projects"* (From the GHG assessment, Arup assumes this to be biosequestration, offsite renewables, and energy efficiency)

The trigger points are grouped into initial considerations and detailed assessments. Achieving the considerations (proven technology, applicability, integration, and environmental risks) would lead to the detailed assessments (commercial viability and opportunities / constraints). This approach is appropriate; however there is no methodology to determine whether a measure achieves the trigger point or what thresholds are to be surpassed. This is of particular importance when determining what constitutes proven technology and commercial viability.

One method in determining the commercial viability of a power generator with the application of CCS is to compare the LRMC (Long Run Marginal Cost) of the wholesale power price with mitigation measures versus the power generator price without mitigation measures but including a carbon price. This may not necessarily demonstrate that the power generator will remain commercially viable, but will set the carbon cost trigger points for when they should consider the mitigation measures.

4.2 Emissions reduction technology

The GHG assessment identifies several emissions reduction technologies including wet cooling (coal and gas options), selective catalytic reduction (NO_x reductions for both the coal and gas options), selective non-catalytic reduction (NO_x reductions for the coal option), dry low NO_x systems (gas fired option), flue gas desulphurisation (coal fired option) and theoretical high efficiency thermal design (coal fired option).

Wet Cooling

As stated earlier, wet cooling has been shown to be inappropriate for the site because of unavailability of the water allocations needed to run the process. The GHG assessment states that if the water was available for wet cooling there would be a net financial benefit to the Project.

NO_x reductions

NO_x emissions are not considered to be greenhouse gases, therefore NO_x catalytic reduction is not considered to represent an emissions reduction technology. Conversely, NO_x reduction technology can reduce actual thermal efficiency of power plants and therefore increase emissions intensity. This increase in emissions intensity has not been acknowledged or calculated for any of the NO_x reduction technologies. Since none of the NO_x reduction technologies form part of the Bayswater B Proposal it could be assumed that they were not included in the GHG emission quantification calculations.

Flue Gas Desulphurisation (FDG)

SO_x emissions are not considered to be greenhouse gases, therefore SO_x reduction is not considered to represent an emissions reduction technology. Flue Gas Desulphurisation can decrease thermal efficiency and increase greenhouse gas emissions intensity. In this case the impact on the emission intensity has been acknowledged and quantified although calculations of this impact have not been included in the EA. The need for FGD if the Post Combustion Carbon Capture technology is retrofitted to the Bayswater B plant is dealt with in section 4.5 Carbon Capture Ready.

Theoretically high efficiency thermal design

As stated earlier in section 3.2.2 Coal fired options, theoretical high efficiency thermal design for the coal fired option has been analysed for cost / benefit to the project and found to be commercially unviable. The decrease in emission intensity (from 0.817 to 0.796 t CO2e/MWh) has been calculated to cost $120/t CO2e reduced. According to Treasury modelling[25] a comparative price for carbon would not be reached until 2038 (in the projects 23rd year of operation) at the earliest under any of the modelling scenarios. However inputs to this calculation are not present in the GHG assessment and it is unclear if the income from the sale of additional electricity generated has been taken into account.

Although the emissions reduction measures in the GHG assessment deal primarily with non-greenhouse gases, some of the analysis provides a useful insight into the effect of reducing other non-GHG emissions on overall GHG emissions intensity.

4.3 Greenhouse gas emissions offsets

Although the EA briefly mentions biosequestration, waste methane, offsite renewable energy and investment in energy efficiency as available carbon offsetting mechanisms, there is no analysis of their costs, scale, appropriateness to the project or their relative effectiveness / environmental benefit.

Arup considers that the measures to offset the greenhouse emissions identified in the GHG assessment have not been explored or analysed to the same level of detail as some other GHG emissions reduction measures (i.e. Carbon Capture and Storage).

4.4 Renewable energy augmentation

The GHG assessment notes solar thermal augmentation and on-site wind generation as two different measures that could directly reduce the Scope 1 greenhouse gas emissions associated with the Bayswater B project. Both technologies are dismissed as “unlikely to be technically feasible” for the site. There is no evidence provided within the Greenhouse Gas Assessment to substantiate this claim.

On-site wind

The predicted wind speeds for the site contained in Appendix D Air Quality Assessment suggest the predominance of light to moderate wind speeds which would prevent wind turbines, small or large, from being financially viable. The conclusion that on site wind is not technical feasibility seems accurate.

Solar thermal augmentation

The first reason for not including solar augmentation in either coal or gas fired option is that the site is "largely shadowed" without further explanation. As the EA states, solar thermal augmentation is already installed at the nearby (just over 10km), Proponent owned, coal fired power station at Liddell. The shadowing is not considered to be a climatic phenomenon within the region. The photos contained in the chapter 12 Land Capability of the EA appear to show an open field which implies there is little likelihood of natural shading from land formations or vegetation. It is possible that shadowing at the site could be caused by the proposed power plant and its associated infrastructure, where the solar field is proposed located south of the infrastructure. However unless this is the only viable space for the solar field this is unlikely to be the case.

The second reason given for not including solar augmentation is that the technology is *"costly in comparison to the scale and the ability to meaningfully offset large scale emissions".* There is no cost of carbon reduction given in the EA. According to Macquarie Generation[29] the Compact Linear Fresnel Reflector (CLFR) array at Liddell cost $5.5 million in 2007 with a capacity of 9MW (thermal) generating 4,400MWh of renewable electricity per year. These figures, REC price forecasts[30] and downward trends in capital costs[31] would suggest that solar augmentation could be capable of being comparable in cost and scale to other greenhouse gas reduction / offsetting measures that have received more thorough analysis within the EA.

Section 5.2 Pulverised Coal Fired Ultra Supercritical Thermal Power Station of the EA states that infrastructure and systems would include: "*Solar Augmentation readiness by the introduction of solar heat into feedwater systems (provision made for future* deployment)". The provision for solar augmentation is not substantiated elsewhere within the main body of the EA, and appears to be contradicted within the GHG assessment.

Biomass co-firing

Another renewable energy augmentation that could be suitable for the Bayswater B coal fired option is biomass co-firing. This involves feeding waste plant matter (e.g. sawdust, bagasse, rice husks etc), or energy crops (e.g. short cycle plantation timber, vegetable oil etc) in with the coal fuel stream. Macquarie Generation's power plants at Liddell and Bayswater already co-fire saw-mill residue and vegetable oil at a rate of 5% by mass or 2% by electricity sent out[32]. It therefore seems logical to assume this approach could be technically feasible and commercially viable for the Bayswater B coal fired option and warrants significant analysis within the GHG assessment and main body of the EA.

Arup considers that the renewable energy augmentation measures to reduce and/or offset the greenhouse emissions identified in the GHG assessment have not been explored or analysed to the same level of detail as other non-renewable GHG emissions reduction measures. The amount of information and analysis presented within the GHG assessment is considered inadequate and unacceptable.

Additional mitigation options that were not identified by the GHG assessment (i.e. biomass co-firing), are likely to be feasible at the commencement and continuing throughout the life of the project.

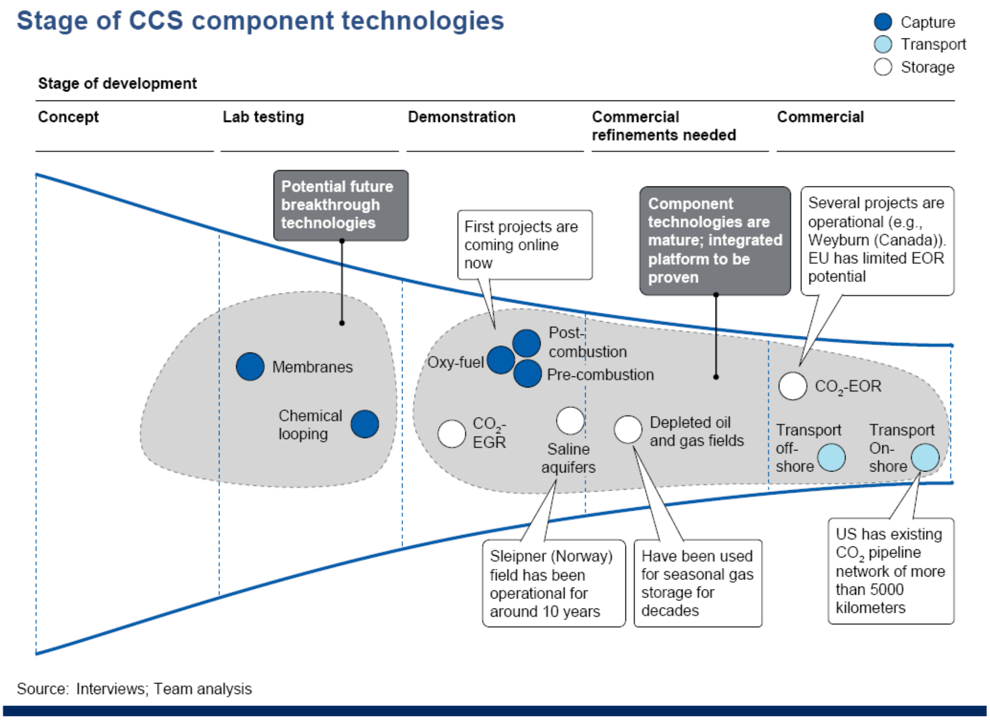
[29] http://www.macgen.com.au/News/2006News/LiddellSolarProjectUpdate.aspx
[30] MMA, 2009, *Benefits and Costs of the Expanded Renewable Energy Target*, Department of Climate Change
[31] Wyld Group et al, 2008, *High Temperature Solar Thermal Technology Roadmap*, NSW and Victorian Governments
[32] Moghtaderi B., 2006, *Australian Bioresources*, BioResources 1 (1), 93-115

4.5 Carbon Capture and Storage

4.5.1 CCS technology types

The GHG assessment names three Carbon Capture technologies currently in demonstration stages (Pre-combustion, Oxy-fuel combustion and Post-combustion carbon capture using chemical solvents) and explains the basic principles of the technologies and their appropriateness for the Bayswater B proposal. Both Pre-combustion and Oxy-fuel combustion technologies are ruled out because of the inability to retro-fit them to the Bayswater B proposal. Although not included in the GHG assessment, there are several less developed carbon capture technologies that are not yet in demonstration phases including a second post-combustion carbon capture technology called calcium carbonate looping. Analysis by McKinsey[33] shows the various CCS technologies and their comparative maturity:

Figure 1 Maturity of CCS technologies (Source: McKinsey and Associates, 2008)



Pre-combustion carbon capture – coal fired option

The reasons given in the GHG assessment for Pre-combustion being unsuitable for retrofitting are explicit for the coal fired option (instead of USC, the plant would need to be IGCC technology, which has already been ruled out for commercial and availability reasons).

Pre-combustion carbon capture – gas fired option

The technical reasons for the unsuitability of retrofitting the gas option (CCGT) with pre-combustion carbon capture are not explained within the GHG assessment. According to an International Energy Agency briefing note[34], although pre-combustion carbon capture retro-fit is technically achievable with CCGT power plants the most economically viable approach is still post-combustion carbon capture.

[33] McKinsey Climate Change Initiative, 2008, *Carbon Capture and Storage: Assessing the Economics*, McKinsey & Company

[34] IEA Greenhouse Gas R&D Programme, 2007, *CO_2 Capture Ready Plants*

Oxy-fuel firing

Oxy-fuel combustion is regarded as unsuitable for the proposal because the coal fired option's boilers will be designed for air and would need to be replaced to take a pure oxygen feed. Although it is not stated, it is assumed that the gas fired option's gas turbine would also need to be replaced. However, the rebuild cost of replacing the boilers in the coal fired option may in fact be comparable to other carbon capture technologies according to analysis by MIT[35].

Post-combustion carbon capture with MEA

Post combustion carbon capture with Metho ethanolamine (MEA) absorbers is presented as the most likely candidate for a future retrofit to the Bayswater B power plant. This technology has been technically proven and tested with 90% collection efficiency, however is yet to demonstrate scalability to suit a 2000 MW coal or gas power generator.

For the successful application of amine based carbon capture, the flue gas needs to be cooled and pre-treatment to reduce particulate levels and acid gases (NO_x and SO_x) to extremely low levels. This means that Flue Gas Desulphurisation and NO_x reduction technologies mentioned earlier in section 4.1 may need to be implemented.

The flue gas is then passed through an amine scrubber column to react the solvent with the CO_2. The CO_2 is removed from the solvent in a stripping column by heating and then compressed and dehydrated for transport.

This application has large energy penalties on the power generator because of the parasitic loads associated with the flue gas treatment (increased back pressure), cooling, solvent heating and CO_2 compression. These penalties typically equate to between 10% points and 15% points depending on the age of the asset, power generator type, fuel properties and solvent technology adopted. For example a coal fired power generator with a thermal efficiency of 36% would reduce to 26% at best, (i.e. 36% - 10% penalty = 26%).

A description of the process is given within the GHG assessments and the costs of three scenarios are analysed. The three scenarios differ in the amount of CO_2 removal between 20%, 50% and 90% (the maximum amount technically feasible with MEA) for both the coal fired and the gas fired options. The analysis shows that the more CO_2 is removed the greater the cost effectiveness of the retrofit. However, there are several key assumptions behind the costs given that are not present in the EA including:

- Total amount of CO_2 removed over the project life;
- Year in which the retrofit would take place, which would determine the amount of CO_2 removed over the life of the project; and the
- Weighted Average Cost of Capital, or WACC, for the investment in a CCS retrofit, which would be required to determine the life-cycle cost of CO_2 removal (\$/t CO_2 e removed).

Other figures used in the analysis of the onsite costs of CO_2 removal using MEA such as the additional capital costs, auxiliary energy required, additional steam heating and the additional equipment cooling by the CCS equipment for the coal option seem reasonably comparable to publically available information[6,35]. However the costs for the gas fired option seem to be an underestimate as they would be expected to be 10% to 20% greater than with the coal fired option according to Arup CCS experts.

Calcium carbonate looping

Arup has included a description of another post combustion carbon capture (one of many) to illustrate the point that choosing one technology for retrofitting could have impacts on the ability of the Project to be retrofitted with other, potentially cheaper technologies.

35 Massachusetts Institute of Technology, 2007, *The Future of Coal: Options for a Carbon-Constrained World*, MIT

The chemical looping process using limestone (calcium carbonate) is one of the promising new carbon capture technologies. This technology does not require the pre-treatment of the flue gas as with MEA discussed above. NO_x or SO_x may still need to be removed (but not to extremely low levels) to meet the relevant statutory requirements for environmental emission limits. The calcium carbonate looping process works by reacting calcium oxide with CO_2 from flue gas in a reactor chamber at elevated temperatures and pressures to produce calcium carbonate. Then CO_2 is then released in a calciner chamber at a slightly lower temperature, recycling the sorbent material back to the reactor with very little energy loss. Even though the parasitic loads associated with CO_2 capture is very small (approximately 1.5% points), compression and dehydration loads remain the same.

This application has the lowest energy penalty on the power generator of 7%, however the technology is still under pilot plant trials and some years away from being technical proven or demonstrated at a large scale. The collection efficiency is expected to exceed 90%, with a target of 95%.

4.5.2 Transport of captured carbon to storage site

As the EA points out, there are currently no CO_2 transport pipelines in NSW, nor are there any applications to build such a pipeline. Costs of building such a pipeline have not been estimated, though there is an explicit statement that there would be an increased cost for longer pipelines. As mentioned earlier, the Proponent has had reports commissioned that estimate the price of such a pipeline.

The costs given for the CO_2 removal do not include the transport and storage components required for Carbon Capture and Storage. The EA suggests the transport and storage costs would constitute an additional 5 to 10%. This figure is lower than publically available information in a report by McKinsey and Company[33] which suggests that for a new European power plant with a storage site 200km away, built after 2020 these costs would be over 24% of the total cost of CCS.

A report conducted by Worley Parsons for Macquarie Generation in 2007[36], could be the source of the transport cost assumptions though it is not mentioned within the EA. This report estimated the cost of the pipeline at between around $1.5 and $5.5 billion for a 632km pipeline from Bayswater to the Darling basin. Arup CCS expert analysis suggests that the costs of transport and storage could be as high as $30/t$CO_2$e.

4.5.3 Potential storage sites

The GHG assessment identified three sites with different geological formations potentially suitable for carbon geosequestration. They are the Darling Basin aquifer, Murrurundi Trough coal seam and the Cooper Basin gas reservoir. These conclusions are echoed by several publically available studies commissioned by the Proponent[37,38, 39] and the NSW Department of Primary Industries. The GHG assessment points out that all of these sites require significant further study / testing before they could be deemed appropriate for CO_2 storage.

Depleted oil and gas reserves present the best opportunities for the geosequestration because the available geological knowledge will assist with carbon injection modelling and locating wells. However, as the GHG assessment points out, the nearest depleted oil and gas reservoir is over 1000 km away which presents a capital cost hurdle.

Deep aquifers present an alternative store option, however additional work is required to determine the size of the store, sealing layer integrity, permeability and plume dispersion modelling. This may take up to three years to install enough test wells to gather sufficient

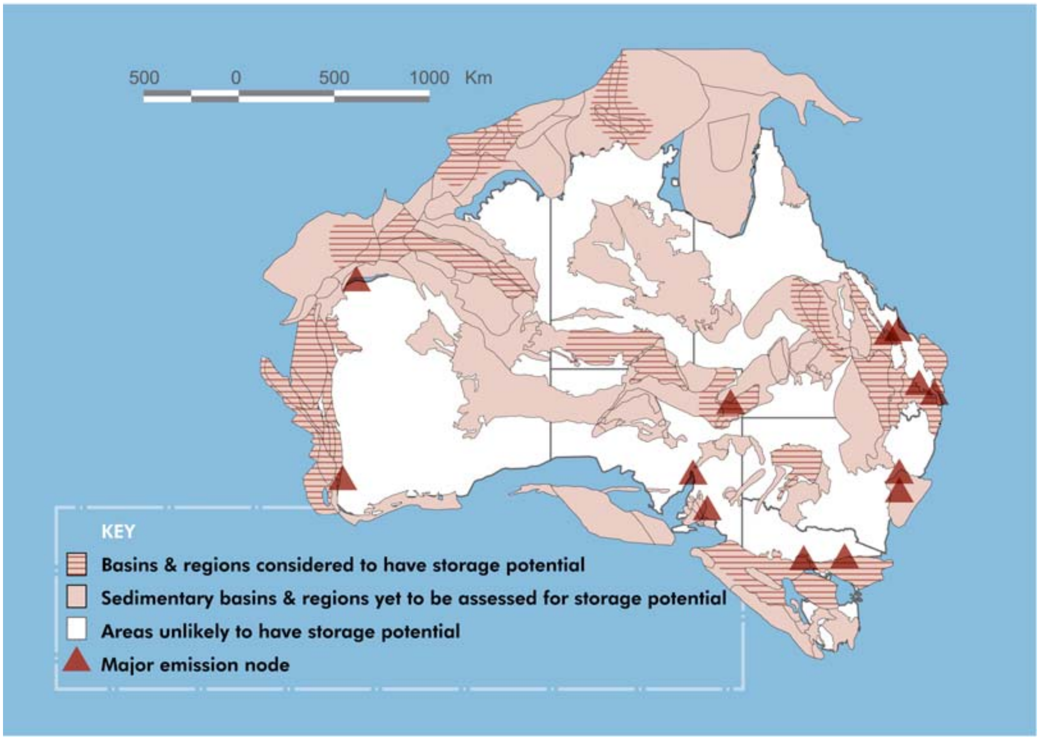
[36] Worley Parsons, 2007, *Geosequestration Compression and Pipeline Study*, Macquarie Generation
[37] FrOG Tech, 2007, *Darling Basin Reservoir Prediction Study*, NSW Department of Primary Industries
[38] Earth Resources Australia, 2006, Potential for Coal Seam Geosequestration of Carbon Dioxide, Macquarie Generation
[39] FrOG Tech, 2007, *Sydney Basin Reservoir Prediction Study*, NSW Department of Primary Industries

geological information for modelling purposes. Potential deep aquifer sequestration sites are approximately 700 km west of Bayswater B Power Station.

The use of deep coal seams for CO_2 geosequestration would lead to conflict with future mining of the coal seams and in Arup's view should be avoided as a potential store.

The figure below shows Australian basins and regions considered to have CO_2 storage potential. Significantly, many of the regions closest to the Bayswater B site are "yet to be assessed" according to the Cooperative Research Centre for Greenhouse Gas Technologies (CO2CRC)[40].

Figure 2 Australian basins and regions considered to have CO_2 storage potential



Source: Cooperative Research Centre for Greenhouse Gas Technologies (CO2CRC)

4.5.4 Carbon Capture ready

CCS does not form part of the Bayswater B proposal, nevertheless the greenhouse gas assessment notes measures that have been taken to ensure the plant would be carbon capture ready if CCS technology becomes commercially available and viable in the future.

To build a carbon capture ready plant would require the pre-nomination of a preferred technology. In Arup's opinion the next five to ten years will see significant advances and development in evolving new carbon capture technologies and therefore places a difficult decision on the designer to lock in a technology today. From the GHG assessment this appears to be MEA based post-combustion carbon capture and storage which is proven, but also quite expensive compared to the estimated costs of other technologies. However, it should be noted that there is likely to be several years before the design of the plant is finalised during which time a preferred technology may emerge.

One approach to carbon capture readiness may be to incorporate provisions suitable for other technologies that do not diminish the opportunities for MEA based post-combustion carbon capture and storage.

[40] Cook, P.J., 2008 *Demonstration and Deployment of Carbon Dioxide Capture and Storage in Australia*, Energy Procedia 00, 000-000. Individual image available at http://www.co2crc.com.au/images/imagelibrary/gen_diag/aus_regions_media.jpg

The GHG assessment mentions the several measures that have been incorporated into the Project to make it carbon capture ready. While the majority of the known measures to make a power plant carbon capture ready seem to have been dealt with[41], it is still unclear if these measures will actually enable carbon capture retrofits in the future because of the infancy of the technology in this application.

Arup considers that the CCS measures to reduce the greenhouse emissions identified in the GHG assessment have been explored to an acceptable level. The GHG assessment has nominated a carbon capture technology for future retrofit and potential storage sites for captured CO_2.

The retrofit cost calculations are incomplete and as a result the carbon price trigger points identified are likely to be underestimates. The potential year of a retrofit has not been identified which means even the partial financial and trigger point analysis is highly uncertain.

[41] IEA Greenhouse Gas R&D Programme, 2007, *CO_2 Capture Ready Plants*

5 Evaluation of the project under the CPRS

5.1 Costs to Bayswater B from carbon price

The DGRs relating to the CPRS obliges the Proponent to evaluate the project under different Australian Emission Unit prices with and without mitigation measures.

The EA evaluates the financial impact of the DGRs prescribed carbon prices ($10, $25 and $50 per AEU) for each of the proposed coal and gas options as well as the CCS retrofit options in a total cost per annum figure. No mitigation measures are included other than CCS. The CCS costs are for the AEU's only, and do not include the cost of installing the CCS technology (which would enable a direct cost/benefit analysis), and none of the costs are related to the yearly operating and maintenance costs of the coal or gas fired options (i.e. the costs without the CPRS), so there is little sense of scale of financial burden.

It appears from the figures being presented as annual costs that they do not include the increased cost of construction that would arise from the introduction of the CPRS. It is also unclear from the EA text if the yearly cost impacts include the increased costs of fuel. Judging by the figures it is likely the cost of scope 3 fugitive GHG emissions from coal mines has been factored into the cost calculations. This implies an assumption that the coal mining companies would pass through 100% of the costs of the carbon price to their customers; this assumption is considered appropriate given the CPRS has yet to begin and a suitable benchmark for cost pass through is yet to be established. It also appears as though the diesel use in coal extraction has not been included in the costs (as with the quantification of emissions).

The GHG assessment also gives the costs of the AEUs as an increase to the cost of generating electricity ($/MWh sent out), but they do not incorporate the long running marginal cost (LRMC) for the electricity generated by the power plant; the impact on prices cannot be compared to the current average wholesale cost of electricity. These electricity price increases are not based on the predicted energy generation of the power station options; rather they are based on an assumption of 15,000GWh p.a. This is unusual given there are more accurate yearly generation estimates contained within the main body of the EA.

The EA does not evaluate any of the mitigation measures (excluding CCS) against these price signals, nor does the EA make any statement about the commercial viability of the Project under those cost constraints. The CCS and emission reduction measures that have been costed in the EA are all well above the three price points given by the DGR (excluding wet cooling), so it is reasonable not to make any direct comparisons to mitigation measures that have already been costed above the three DGR price points. However, there are many emissions mitigation measures which are not costed or thoroughly investigated within the GHG assessment or the main body of the EA. These include:

- Solar augmentation
- On-site wind generation
- Biomass co-firing
- Bio-sequestration
- Off-site renewable projects
- Energy efficiency projects
- Waste methane projects

Arup considers that evaluation of the project under the CPRS is inadequate in that it does not include a comparison to costs without the CPRS and is incomplete in that it does not evaluate the project with or without mitigation measures.

5.2 Impacts of the CPRS

There is no analysis of how the electricity market will adjust itself under a CPRS, as the most carbon intensive generators are replaced by low carbon and renewable options within the electricity market. The GHG assessment states that:

> *"While there has been ongoing discussion of the proposed CPRS by the Federal Government and various authorities, at this point in time the following details of the scheme are unknown:*
>
> - *The date at which a CPRS would be introduced*
> - *Terms and conditions of the scheme*
> - *Carbon price level/s (i.e. dollars per tonne of CO2 emissions)*
> - *Government policy regarding how the scheme would be implemented with regards to electricity generators."*

While these points are largely true because the scheme is yet to pass parliament, the Federal Government has made a large amount of information about the scheme and the economic forecast modelling freely available to the public. These include a start date for the scheme (which is extremely likely to be before 2015), forecasts of average yearly carbon prices or price of Australian Emission Units (AEUs), and the most current compensation to existing energy generators that is planned. The following points are freely available information on the CPRS from various Government Department websites:

- At present the scheme is scheduled to begin in July 2011 at a fixed price for one year until July 2012 when full flexible price trading commences[42].
- AEU carbon prices are expected to be $10 in July 2011[42], $25 by 2013 (under the CPRS 5 scenario) and $50 by 2020 or 2029 (under the CPRS 15 and CPRS 5 scenarios respectively); by 2044 (the last year of the Project's operations) the AEU price is expected to be above $90 (under the CPRS 5 scenario) [43].
- Financial assistance to coal fired electricity generators will be available to generators with emission intensities above 0.86tCO_2e/MWh and that were in operation before June 2007[44].

Using this information Arup considers that the CPRS is likely to have several impacts on the project and potential mitigation. As an indication of what a thorough analysis of these impacts could look like, Arup has compared long running marginal cost (LRMC) estimates for different generation technologies and mitigation measures under the different AEU price signals.

> Long Run Marginal Cost is a widely used method in the electricity generation sector for determining costs of investment in new electricity generation infrastructure on per unit of generation basis. LRMC is a measure made up of factors including the capital costs of building the power plant, as well as the operating, maintenance, fuel and financing costs. LRMC is used to estimate the average price the generator would need to charge for electricity over the life of the project.
>
> As such, Arup considers that LRMC is the most appropriate methodology for evaluating the commercial viability of any emissions reduction/offsetting measures.

42 http://www.climatechange.gov.au/emissionstrading/timetable.html accessed on 6/10/2009
43 http://www.treasury.gov.au/lowpollutionfuture/spreadsheets/report_charts/Chapter%206/Chart%206.3%20-%20%20Australian%20emission%20price.xls
44 http://www.climatechange.gov.au/emissionstrading/legislation/pubs/coal-fired_electricity_generation.pdf

The following figures show an indicative LRMC of the impact of the DGR determined AEU price signals. The base LRMC figures for USC, CCGT, IGCC and IGCC with CCS are based on analysis for new entrant power plants in NSW in 2015 calculated within a report by ACIL Tasman[11] . Additional costs relating to CCS for USC and CCGT are based on costs contained in the GHG assessment. Solar augmentation LRMC costs are based on a range (indicated by error bars) of figures given in a report by the Wyld Group and MMA[31]. Offsite renewable LRMC based on a cost range (indicated by error bars) published by the Australian Energy Regulator[45].

Figure 3 Indicative LRMC excluding carbon price

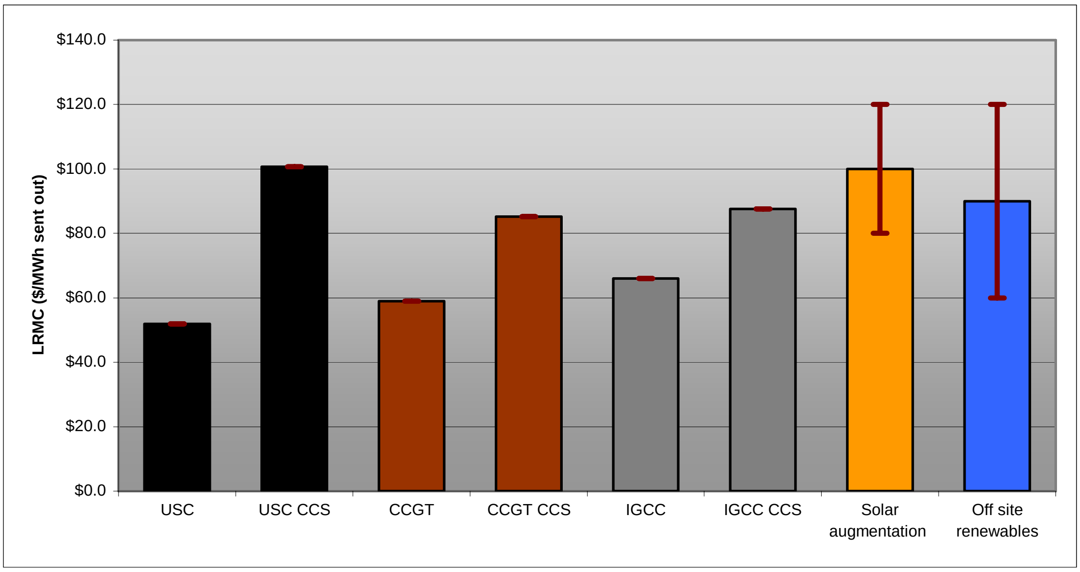
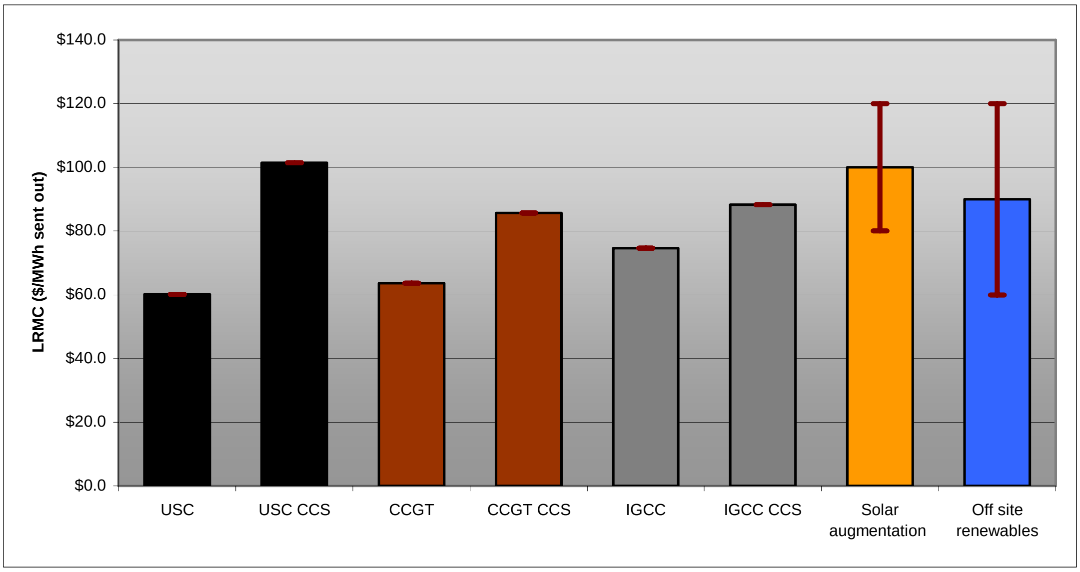


Figure 4 Indicative LRMC with $10/t AUE price



[45] Australian Energy Regulator, 2009, *State of the Energy Market 2008*, Figure 1.2

Figure 5 Indicative LRMC with $25/t AEU price

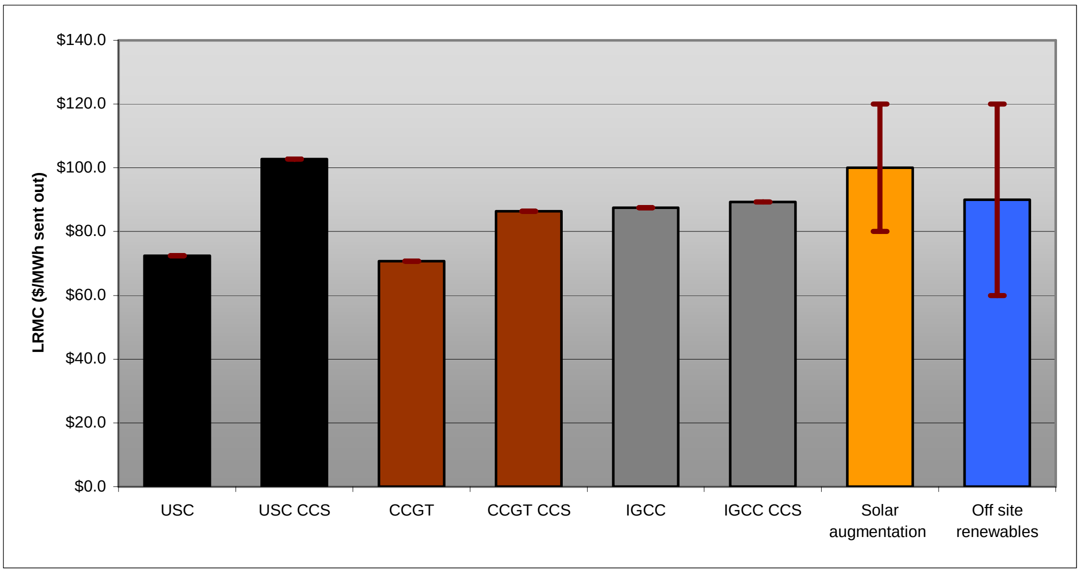
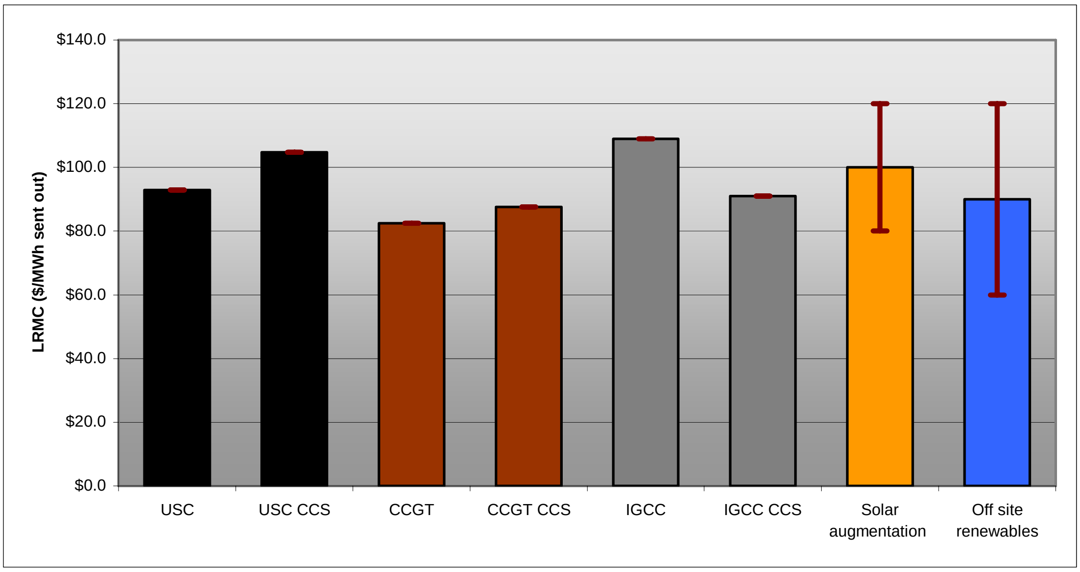


Figure 6 Indicative LRMC with $50/t AEU price



While Figure 3 to Figure 6 above are indicative only, they show that the gas fired option becomes more viable than the coal fired option at a carbon price of less than $25 per tonne. They also show that solar augmentation may be just as viable as CCS technology. These conclusions are based on generic preliminary data as well as data taken from the GHG assessment which as discussed throughout this review contain several weaknesses. In order to support these conclusions a more thorough analysis LRMC of options is required.

Ultimately the analysis of the options at any one static carbon price is not realistic as the carbon price will fluctuate with the market over the lifespan of the project. To evaluate the project with and without mitigation measures under the CPRS would require the application of a model tracking these fluctuations.

Although the CPRS is yet to be finalised, Arup considers that there is enough publically available information to warrant a much more comprehensive review of the impacts of the Scheme than what is currently contained in the GHG assessment.

6 Recommended conditions

In NSW greenhouse gas emissions from electricity generators are currently regulated by the NSW GGAS Scheme. However, by the time the project is in operation, it is likely that the GGAS Scheme will have ceased and the Commonwealth Government's CPRS will be in place.

The CPRS will reduce greenhouse gas emissions across the national economy by establishing national emission limits which are then achieved through market based mechanisms involving the trade of AEUs. It has been argued, that under such a policy setting there is no need for greenhouse gas emissions to be regulated or even considered under the planning assessment process as the market will ensure that total national emission limits are not exceeded[46].

However, failure of proponents to adequately evaluate the impacts of the CPRS on projects prior to implementation may result in projects which are not financially viable or have a reduced lifespan. Projects with nationally significant greenhouse gas emissions may also impact on the CPRS itself resulting in increased costs of AEUs with flow on effects to the wider economy.

Arup therefore recommends that the Department of Planning stipulate conditions of approval which will ensure that the impacts of the CPRS on the financial viability of the project are fully addressed both prior to approval and throughout the project life. This would include conditions which require the Proponent to accurately and comprehensively quantify greenhouse gas emissions and justify the preferred project options on a financial basis incorporating a price on carbon.

Arup recommends that conditions are imposed at two stages over the life of the project. Prior to approval, it is recommended that all potential options are evaluated and compared based on the best available models for a carbon price trajectory and technology costs (See Section 6.1).

Secondly, that over the life of the project, options to mitigate emissions and adopt augmentation technology including CCS and solar augmentation are periodically assessed as new and updated information relating to carbon price, technology costs and technological developments emerge (See Section 6.2).

6.1 Evaluation of Project Prior to Determination

Prior to Project Application determination the proponent should prepare an evaluation of the LRMC of electricity generation for the following minimum options:

- USC coal
- USC coal retrofitted with integrated CCS at a later date (up to theoretical maximum % capture)
    - CCS retrofitted at earliest point in time when it is considered likely that storage location is identified and pipeline constructed
    - CCS retrofitted at nominal periods from this time over the life of the facility
- CCGT
- CCGT retrofitted with integrated CCS at a later date (up to theoretical maximum % capture)

[46] See for example industry submissions to the to the 10 year review of the Environment Protection and Biodiversity Conservation Act 1999 in relation to the proposed greenhouse trigger for Commonwealth assessment of projects (Santos, Woodside, APPEA) http://www.environment.gov.au/epbc/review/submissions/index.html.

    - CCS installed at earliest point in time when it is considered likely that storage location is identified and pipeline constructed
    - CCS retrofitted at nominal periods from this time over the life of the facility
- Solar augmentation of USC coal (up to the maximum technically available land area)
- Solar augmentation of CCGT (up to the maximum technically available land area)
    - Solar augmentation at installed at project commencement
    - Solar augmentation installed at nominal periods over the life of the facility
- Biomass co-firing with USC coal (up to the theoretically maximum % achievable)
    - Biomass co-firing provisions installed at project commencement
    - Biomass co-firing provisions installed at nominal periods over the life of the facility

The LRMC should be determined over the 30 year life of the project using a fluctuating carbon price model[47] for all options (noting that technologies installed at a later date with have reduced life spans).

The LRMC analysis should be used to justify the final selected technology option.

6.2 Evaluation of Mitigation Options over Project Life

Over the life of the project, the proponent should be required to update the LRMC analysis in Section 6.1 above at regular periods. The updated analysis may exclude options which are no longer possible (such as USC coal options if CCGT is installed).

The analysis should be updated to reflect,

- any revised modelling of fluctuating carbon price impacts,
- the actual cost of capital for the initial plant
- new information relating to the costs of technology
- new information relating the capacity of new technology
- emerging augmentation technology

Where the LRMC analysis shows that an augmentation technology compares favourably then the proponent should be required to implement the technology (unless other non financial justification can be provided such as unacceptable environmental impacts, issues with supply chain etc).

[47] Arup considers that the most applicable carbon price modelling currently available is the modelling undertaken by McLennan Magnesia Associates for Treasury to inform the CPRS White Paper http://www.treasury.gov.au/lowpollutionfuture/spreadsheets/report_charts/Chapter%206/Chart%206.3%20-%20%20Australian%20emission%20price.xls

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