NSW Department of Planning

Independent Review of Greenhouse Gas Assessments

Mt Piper Power Station Extension

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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 Mt Piper Power Station Extension Concept Plan. The Greenhouse Gas Assessment has been prepared by Sinclair Knight Mertz (SKM) on behalf of Delta Electricity. 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

Delta Electricity is seeking concept plan approval to increase the generation capacity of the existing Mt Piper Power Station at 350 Boulder Road, Portland, NSW. The two existing 700MW coal fired generators at the site were originally commissioned in 1992 and 1993. Concept plan approval is now being sought for two potential options to expand the generation capacity:

- Option 1 – 2 × 1000MW Ultra super critical (USC) coal fired power generators; and
- Option 2 - 6× 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 Delta) and would be subject to approval under a separate Project Application to the Department of Planning.

The Concept Plan EA 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]. The EAs for each project and therefore this independent review do not take into account the cumulative impacts of the projects.

[1] Bayswater B Power Station Concept Plan (2000MW USC coal fired or CCGT) <http://majorprojects.planning.nsw.gov.au/index.pl?action=view_job&job_id=3327> 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>

1.2 Director General Requirements

Director General Requirements (DGRs) 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: DGRS 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. 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 reasonable 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 EA prepared by SKM and in particular the Greenhouse Gas (GHG) Assessment contained in Appendix F of the EA. This independent review should be read in conjunction with this document

The independent review assumes that the information provided in the EA or GHG Assessment 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, operation and decommissioning of the expanded power station.

In accordance with the DGRs, the GHG 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 during project operation from the combustion of fuels. Scope 2 emissions are defined as emissions resulting from the consumption of purchased electricity of which there is assumed to be none. 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

2.2.1 Scope 1 Emissions

The GHG Assessment defines Scope 1 emissions as those emissions that occur as a result of fuel combustion on site for the purposes of generating electricity. For the USC coal options, this involves combustion of black coal. For the CCGT option this involves combustion of natural gas. The GHG Assessment has calculated the emissions associated with fuel based on estimated annual fuel combustion and fuel combustion emission factors provided in *NGA Factors* (Department of Climate Change, November 2008) document for each technology option using the following equation:

$$E_{ij} = {(Q_{ij} \times EC_j \times EF_{ijoxec})} / {1000}$$

where:

E_{ij} = Emissions of gas type (j), CO_2, CH_4 or N_2O, from fuel type (i) (CO_2-e tonnes).

Q_i = The quantity of fuel type (i) (tonnes or m³) combusted

EC_j = The energy content factor of fuel type i (GJ/tonne or m³)

EF_j = Emission factor for each gas type (j) (which includes the effect of an oxidation factor) for fuel type (i) (kg CO_2-e / GJ)

The GHG Assessment has sourced default parameter values for the above equation from the NGA Factors document. The exception to this is quantity of fuel combusted which is particular to each option.

The technical adequacy of the quantification of Scope 1 emissions in the GHG Assessment is therefore dependent on the assumptions used to estimate fuel consumption. The fuel consumption values are not explicitly stated for either the USC coal or CCGT option. Arup has provided a review of the calculations to determine and assess the appropriateness of the assumptions used to determine annual fuel consumption for the purposes of determining annual Scope 1 emissions.

Annual fuel consumption of each generation plant is largely determined by the thermal efficiency of the plant, the auxiliary load and the capacity factor.

$$Qi = \frac{(CF \times NetCapacity + AuxLoad) \times PeriodHours \times 3.6}{\eta_{thermal} \times EC_i}$$

where:

Q_i = The quantity of fuel type (i) (tonnes or m³) combusted

CF = Capacity Factor (%)

Aux Load = Auxiliary Load (MW)

Net Capacity = Total Installed Capacity - Auxiliary Load (MW)

Period Hours = Number of hours in period of analysis (in this case one year)

$\eta_{thermal}$ =Thermal Efficiency (%)

EC_j = The energy content factor of fuel type (i) (GJ/tonnes or GJ/m³)

Arup has therefore provided a review of these assumptions to inform the independent review. These are summarised in Table 1 and discussed below.

Table 1 Assumptions for Scope 1 emissions in GHG Assessment

Parameter	Value adopted in GHG Assessment	
	USC coal	CCGT
Installed Capacity[1]	2000 MW	2400 MW
Net Capacity[1]	1,839 MW	2,293 MW
Auxiliary Load[2]	161 MW	107 MW
Capacity Factor[3]	80%	80%
Thermal Efficiency[4]	39.2%	51.6%
Energy Content of Fuel[5]	27.0 GJ/ tonne	39.3×10^{-3} GJ/ m³
Annual Fuel Consumption[6]	2.86×10^{6} m³ (112.2 PJ)	4.4 Mt (118.3 PJ)

1 As stated in the GHG Assessment

2 Auxiliary load has been calculated by Arup based on the difference between the gross and net ratings provided in the GHG Assessment

3 Capacity factor refers to the percentage of the total installed electrical capacity of the generating system that is actually generated, averaged over an annual period. That is, capacity factor takes into account foregone generation when the plant is operating at reduced capacity such as during start ups, shut downs and periods of reduced demand. For each option, the GHG Assessment states that the plant is operating at an average capacity factor of 80%. The source of the 80% assumption is a 2008 Connell Wagner study[2]. This is assumed to represent likely typical operation. In the GHG Assessment, the 80% capacity factor excludes auxiliary losses which is considered consistent with the definition of capacity factor as defined by the Department of Climate Change[3] and the Energy Supply Association of Australia (ESAA)[4].

4 Thermal efficiency refers to the percentage of the total energy value of the fuel that is actually converted to electricity and sent out to the grid. For the USC coal plant the thermal efficiency is explicitly stated as 39.1%. The thermal efficiency for the CCGT plant is not explicitly stated but from the data presented, it can be inferred that the thermal efficiency

[2] Connel Wagner, *Mt Piper Extension project. Plant Definition Study. Delta June 2008 (referenced by Proponent and not review*
[3] AGO, Generator Efficiency Standards
[4] ESAA, Electricity Gas Australia, 2009 at 88

value assumed is 51.6% (See Section 3.1.1). These values correlate with the design efficiencies of both options and would likely represent a best case scenario. Annual average thermal efficiency is likely to be less than the design efficiency values to account for times when the plant is not operating at its highest efficiency

5 NGA Factors default values

6 Fuel consumption values for this typical operation scenario are not explicitly provided in the GHG Assessment and have been calculated by Arup based on above data

The total annual emissions have been based on the annual average fuel consumption values presented in Table 1. Arup considers that these may represent underestimates of actual annual emissions for two key reasons:

Firstly, while an 80%capacity factor may be considered a reasonable assumption for typical operation[5], for the purposes of calculating total annual fuel consumption and emissions, it may be appropriate to report emission levels at the theoretical maximum. This would represent a worst case scenario for comparison.

The values for theoretical fuel consumption maximum emissions as calculated by Arup are below.

For the USC coal option:

- theoretical maximum coal consumption is estimated to be 5.5 Mt per annum; and
- average emissions are estimated to be 13.1 Mt CO_2-e per annum

For the CCGT option:

- Average gas consumption is estimated to be 140.3 PJ per annum
- Average emissions are estimated to be 7.20 Mt CO_2-e per annum

Secondly, the values for thermal efficiency adopted in determining fuel consumption are based on design efficiencies which are likely to represent the maximum thermal efficiencies able to be achieved by the plants. Under the typical operation scenario at reduced capacity, the annual average thermal efficiency is likely to be less than the design efficiency implying that the values for typical operation may be underestimates.

Furthermore, it has been determined by Arup that the total annual average emissions for the typical operation as calculated by SKM are based on a coal throughput of 4.3Mt per annum. This conflicts with the value of expected coal requirements of "*more than 5 Mtpa*" stated in Section 3.3.6 of the main body of the Environmental Assessment and 5.7 Mtpa stated in Section 4.4.3 of the greenhouse gas assessment.

Arup considers that total annual emissions for both the USC coal and CCGT options presented in the GHG Assessment are likely to be underestimates. Conservative worst case estimates by Arup suggest that the total annual emissions could be up to 20% higher than the values presented in the greenhouse gas assessment. This is due to assumptions for thermal efficiency and use of the typical rather than theoretical maximum scenario used by the Proponent which may not be appropriate for the purposes of the assessment. In practice, the annual emissions are likely to range somewhere between this worst case and the estimates provided in the GHG Assessment.

Further, the annual average coal consumption implied by the annual average emissions level is inconsistent (around 20% less) with values for annual coal consumption stated elsewhere in the Environmental Assessment (Section 3.3.6 of the main body of the EA and Section 4.4.3 of the greenhouse gas assessment).

5 Roughly compares with value for NSW average capacity as published in n4 at 21

2.2.2 Scope 2 Emissions

Electricity used on site is assumed to be sourced directly from the generator and therefore included in Scope 1 emissions. This is considered to be a reasonable approach as electricity is only likely to be purchased in the event of a total shutdown of the plant which would represent a very small proportion of the time.

Arup considers the approach to assessing Scope 2 emissions is reasonable and that Scope 2 emissions associated with the project are negligible.

2.2.3 Scope 3 Emissions

Construction Materials

The embodied carbon in construction materials is assumed to be dominated by the volumes of concrete and steel which is considered reasonable given the relative volumes and emission intensities of these materials compared to other chemicals and other materials. The embodied carbon emission factors for steel and concrete are also reasonable considering current technology. However, since the plant will not be constructed until 2014 at the earliest, some consideration could be given to adoption of reduced emission factors using materials with higher recycled content or more efficient processes.

The total volumes of concrete and steel are stated to be estimated from “a desktop search for relevant quantities of concrete and steel”. For the purposes of embodied carbon calculations, Arup generally uses the Australian LCA database[6]. 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 Environmental Assessment for the tow options for the proposed power plant.

Table 2 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 coal fired power plant	Mt Piper proposed 2000MW coal fired 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 (tCO_2 -e)	572,000	623,000	135,144
Embodied Carbon* (tCO_2-e/MW)	217	312	68

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

[6] 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

Table 3 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 embodied emissions calculations contained within the Mt Piper Extension GHG Assessment are significantly less than for other similar plants on a per MW basis. Further, the lifecycle assessment undertaken by Odeh and Cockerill (2008) for UK coal fired power plants indicated that embodied emissions in construction materials and construction energy use represent approximately 0.4% to 0.5% of total lifecycle emissions[7]. The Mt Piper GHG Assessment for the coal fired power plant suggests that embodied emissions in construction materials represent less than 0.05% of lifecycle emissions[8]. These comparisons indicate that the Mt Piper assessment may have underestimated the quantity of concrete and steel required for the construction of the power plants and therefore the total embodied emissions in materials. This underestimate may be significant.

Construction Plant and Equipment

There is no assessment of energy use by construction plant and equipment. Emissions from construction plant and equipment are likely to be significant compared to other construction period emissions. However, construction period emissions in general are not likely to be material to the assessment given that construction is a once off activity. The omission of construction plant and equipment emissions is therefore considered immaterial to the assessment.

Construction Transport

Transportation of construction materials is calculated based on approximate fuel consumption rates of a semi trailer and cement trucks. These are considered suitably conservative and in any case result in total emissions which are not material to the assessment.

Land Clearing during Construction

There is no consideration of Scope 3 emissions from land clearing during in terms of either emissions from waste vegetation and future foregone sequestration. However given the relatively small area of the site and management measures to prevent the clearance or replacement of significant vegetation these emissions are not likely to be significant

[7] Odeh, N., Cockeril, T., Life cycle analysis of UK coal fired power plants, Energy Conversion and Management 49 (2008) 212–220 at 215
[8] Based on 30 year operational life

Fuel Extraction and Processing and Supply – Coal

The environmental assessment assumes that the coal resource would likely be supplied for the Cobbora mine approximately 200km from the site. Currently, only an explorative licence for the Cobbora region has been granted to the mine proponents by the NSW Department of Primary Industries and no planning application for any mine in the region has been lodged[9]. Notwithstanding, the fugitive emissions calculated by the Environmental Assessment for coal extraction are generic for open cut mines and are likely to be appropriate where the coal is supplied from any open cut mine in NSW.

There is no assessment of the energy requirements for extraction and processing of the coal and associated emissions. The Australian LCA database suggests that the greenhouse gas emissions associated with this energy use represent approximately 12.1% of upstream emissions.

The transport of coal to Mt Piper has been based on rail transport over a roundtrip distance of 400 km to the Cobbora mine and approximate diesel fuel consumption rates and coal carrying capacity of trains. The assumptions are considered appropriately conservative and in any case result in total emissions which are not material to the assessment.

If the coal is sourced from Cobbora then the railway line will require upgrading. The embodied emissions for any rail construction have not been included in the assessment and should be considered as a further source of Scope 3 emissions for the project.

In total, the upstream emissions for coal supply are stated as 312 Mt CO2-e per year of operation.

An alternative method for calculating Scope 3 emissions from the coal extraction, processing and supply is the use of the Scope 3 emission factor for black coal provided in the NGA Factors workbook of 4.6 kg CO2-e per GJ of black coal to estimate indirect emissions attributable to the extraction, production and transport. This represents the current annual average for black coal in Australia and is therefore indicative only but provides a useful measure for comparison.

Using the NGA Factors Scope 3 emission factor for black coal at theoretical maximum operating conditions gives total Scope 3 emissions of 681Mt CO_2-e which is comparable with the site specific value of 312Mt CO_2-e. Both values are considered highly uncertain with the site specific value presented in the GHG Assessment likely to be an underestimate as it excludes any emissions associated with coal processing.

Fuel Extraction, Processing and Supply – Gas

The GHG Assessment uses the Scope 3 emission factor prescribed for upstream emissions for the supply of natural gas in NSW by the NGA Factors document. These factors are highly dependent of the distance over which natural gas is transported due to the energy requirements of pumping and the fugitive emissions that occur through leakages over the pipeline distance. Therefore NSW currently has the highest Scope 3 emission factor for natural gas consumption due to the distance of the Moomba to Sydney pipeline. It is likely that this factor will decrease in the future as coal seam methane reserves come on line and transported via pipeline from Queensland and potentially NSW.

In total the upstream emissions for gas supply are stated as 2,088 Mt CO_2-e per year of operation.

[9] NSW Government, Media Release: Government Acts to Secure Supply to Power Stations Friday 15 May, 2009

The methodology is considered appropriate given the lack of certainty around future gas supply to NSW. However is should be noted that the value presented is highly uncertain and is likely to be an overestimate.

Emissions from Waste

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

Decommissioning

The GHG Assessment includes a qualitative assessment of the likely emissions during decommissioning including fuel use in plant and equipment and transport of the decommissioned plant offsite. While no quantitative estimate of emissions is provided, Arup considers that these emissions are not likely to be material to the assessment over the life of the project[10].

Arup considers that the approach adopted for the quantification of fuel extraction, processing and supply is generally acceptable given the high degree of uncertainty around future fuel supplies and provides an acceptable estimate of Scope 3 emissions during operation.

Arup considers that there are several sources of Scope 3 emissions for the construction period which have not been included within the assessment and further that embodied emissions in construction materials may have been underestimated. As a result total construction period Scope 3 emissions are likely to have been significantly 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.

[10] This is supported by the UK LCA coal fired power plants n7 at 215 which suggest that emissions from decommissioning emissions constitute 10% of construction emissions and therefore less than 0.005% of total lifecycle emissions.

3 Comparison of emissions intensity and thermal efficiency

3.1 Comparison Against Best Practice Thermal Efficiency

3.1.1 Calculation of Thermal Efficiency

USC coal

The GHG Assessment explicitly states a value for the thermal efficiencies for coal fired power plant of 39.2%. This is assumed to be based on plant specifications for design efficiency rather than an estimate of average thermal efficiency in operation. Where this thermal efficiency is used in calculations of total average annual emissions it is likely to result in an underestimate of annual average fuel consumption and therefore result in an underestimate of annual average emissions (See Section 2.2.1).

Notwithstanding, the use of this thermal efficiency is considered appropriate for the purposes of benchmarking against reported values for similar plants in operation which are reported in terms of design efficiency. (See Section 3.1).

Gas

The GHG Assessment does not explicitly state the thermal efficiency of the proposed CCGT and instead reports that "*typical installed efficiencies range from* 50 to 55% HHV". The assessment implies that there are a number of configurations of gas turbines (GT), heat recovery steam generators (HRSG) and condensing steam turbines (ST) that could be considered. However, the assessment does not discuss the relative thermal efficiencies of each option nor why the final analysis was completed for a configuration of a 6 X400MW system comprised each of 1 GT, 1 HRSG and one ST.

It appears that despite completing analysis on one particular option, the project has not committed to any one technology type and as stated in Section 3.4.2 of the main body of the EA that "*the actual size and capacity of the plant will depend upon their commercial availability at the time of tender*". It may therefore be too early in the design process to predict with certainty the thermal efficiency of the CCGT option.

In Section 3.4.2 of the main body of the EA, there is a discussion of the different CCGT options currently available on the market and the relative thermal efficiencies of each type. Section 3.4.2 further states that "*data for the study is GE 9FB design has been used in the study*". It is also confirmed in the GHG Assessment that the GE 9FB model has been assumed. The reason for assuming this model is stated in Section 3.4.2 of the main body of the EA as "*the design tends to have the largest envelope of requirements and produce the greatest impact*". This is not further explained and may be referring to the design having the greatest net capacity (but not the best thermal efficiency).

The estimated site-based thermal efficiency of this model is stated as 51.8% in Table 3-2 of the main body of the EA. Further, an analysis of the calculations undertaken for emissions intensity reveals that a value of 51.6% was adopted for the annual average operation. This is considered appropriate for such a plant operating at design capacity given the range of values reported in the main body of the EA.

Where this thermal efficiency is used in calculations of total average annual emissions it is likely to result in an underestimate of annual average fuel consumption and therefore result in an underestimate of annual average emissions (See Section 2.2.1). Notwithstanding, the use of this thermal efficiency is considered appropriate for the purposes of benchmarking against reported values for similar plants in operation which are reported in terms of design efficiency. (See Section 3.1).

3.1.2 Comparison with Best Practice

The Department of Planning has confirmed that the comparison against best achievable practice should be specific to the fuel type[11] rather than for baseload electricity generation in general. The GHG Assessment focuses on the selected technological options of USC coal and CCGT and does not compare thermal efficiencies of a range of technology options including open-cycle gas turbines or integrated gasification combined cycle (coal). This is reasonable 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[12].

There is no direct comparison of best practice thermal efficiency for the selected technology options within the GHG Assessment with some analysis of alternatives presented elsewhere in the main body of the EA. Arup has summarised the information presented as well as an analysis of best practice thermal efficiency for the selected technologies below.

CCGT

For CCGT, there are a range of technologies available. The GHG Assessment nominates a 9FB gas turbine model in a configuration of 1 GT, 1 HRSG and 1 ST for analysis for the purpose of the assessment, but the main body of the EA does not commit to any one specific turbine technology as discussed above.

The highest thermal efficiency (and therefore lowest emissions intensity) for CCGT technology can be achieved with wet cooling which reduces the pressure in the low pressure end of the steam cycle increasing the capacity of the steam turbines and the total efficiency of the system. Wet cooling also has reduced auxiliary power consumption compared to air cooling. Wet cooling thermal efficiencies for theoretical CCGT technology reported in the main body of the EA range 52.7% and 54.5%[13]. Air cooled technology at site specific conditions is reported to have reduced thermal efficiencies in the range of 51.3% to 52.9%.

Despite the increased efficiencies, the option of wet cooling has been ruled out due to the high level of water consumption and to ensure that the power station does not require any additional drawing on the Coxs River or Fish River Supply Schemes beyond its existing licence arrangements.

Section 3 of the main body of the EA compares the thermal efficiencies of a number of CCGT technologies for site specific air cooled conditions which has been reproduced in Table 4 below.

[11] Pers Comms, Dinuka McKenzie (DoP), 7/10/2009, email entitled *RE: Clarification* to Peter Rand (Arup)
[12] Owen, A, 2007, Inquiry into Electricity Supply Within the State (Owen Inquiry).
[13] For a theoretical plant at sea level, 15°C, 60% humidity and a configuration of 1 GT, 1 HRSG and 1 ST

Table 4 Mt Piper EA gas turbine analysis[14]

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 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 adopted in the assessment which would have a thermal efficiency 51.8%. The GHG Assessment nominates a 9FB gas turbine model in a configuration of 1 GT, 1 HRSG and 1 ST for analysis for the purpose of the assessment, but the main body of the EA does not commit to any one specific turbine technology.

While the EA does not commit to any one CCGT technology, Arup considers that the 9FB gas turbine used in the analysis <u>is not the best achievable practice</u> for emissions intensity and thermal efficiency in gas fired generation. An H class based CCGT is achievable and has higher thermal efficiency and lower emissions intensity.

3.1.3 USC coal

The GHG Assessment provides an analysis of the estimated thermal efficiency for the USC coal option only against a theoretical high efficiency USC coal plant in accordance with the Best Available Technology efficiency tables in the AGO Generator Efficiency Standards. The GHG Assessments recognises the limitation of the published efficiencies in the application to the specific site conditions and does not consider it to "*represent a reasonable basis*" for comparison. While this is acknowledged, there is no further identification of what would be a reasonable basis for comparison.

The GHG Assessment states that the thermal efficiency of 39.2 % is to represent best commercially available technology based on the reported operating steam conditions and dry air cooled condenser pressure reported. While it is acknowledged that the operating conditions represent an improvement on existing international commercial plants, to validate this statement, further information is required about the plant configuration and the extent to which options to improve the overall plant efficiency have been explored. For example, the EA produced for the proposed Bayswater B USC coal plant states that the inclusion of additional stages of regenerative feedwater heaters and a larger air cooled condenser to reduce steam exhaust conditions could theoretically increase the thermal efficiency from 39.5% to 40.2%.

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

Arup considers that there is insufficient information to determine whether the reported thermal efficiency for the USC coal option <u>is the best achievable practice</u> for emissions intensity and thermal efficiency in coal fired generation. Notwithstanding, the reported steam conditions for the boiler technology are comparable with existing commercial USC coal plants world wide. Therefore the thermal efficiency for the proposed USC coal option is likely to be comparable with these plants.

3.2 Comparison Against Current NSW Average Emissions intensity

3.2.1 Calculation of Project Emissions intensity

Coal

The GHG Assessment provides three separate values for emissions intensity:

- 0.834 t CO_2-e per MWh sent out - based on the methodology prescribed by the AGO Generator Efficiency Standards (GES) using an emission factor specific to Cobbora coal for a plant operating at its theoretical maximum capacity.
- 0.813 t CO2-e per MWh sent out- using the GES methodology above but replacing the Cobbora emission factor with the generic emission factor for black coal prescribed by the NGA Factors document. This is considered the most applicable value to meet the DGRs.
- 0.838 t CO_2-e per MWh sent out – as above but includes coal mine fugitive emissions for the purposes of comparison with values published for the NSW Greenhouse Gas Abatement Scheme (GGAS).

The assessment also implies that the emissions intensity at 80% capacity as stated in Table 4.3 is equal to the emissions intensity at theoretical maximum capacity as stated on page 26. This assumes that the same thermal efficiency has been used to calculate emissions intensity for both scenarios. In real terms, it would be expected that the average emissions intensity at 80% capacity would be slightly greater than at the theoretical maximum capacity due to the reduced thermal efficiencies during start up, shut down and operation below design capacity for some period of time. Therefore, it is considered that the emissions intensity values may have been underestimated as they apply to a typical annual average.

Gas

The GHG Assessment provides a value of 0.358 t CO2-e per MWh for the gas option. This value is stated to be *the annual average emissions intensity for a plant operating at a capacity factor of 80% by adjusting the design efficiency for variation in ambient conditions and part load operation*. However, a review of the calculations reveals that a thermal efficiency of 51.6% has been used which matches with the site specific design efficiency presented in emissions intensity. This implies that the thermal efficiency has not been adjusted to represent part load operation. In real terms, it would be expected that the average emissions intensity at 80% capacity would be slightly greater than at the theoretical maximum capacity due to the reduced thermal efficiencies during start up, shut down and operation below design capacity for some period of time. Therefore, it is considered that the emissions intensity values may have been underestimated as they apply to a typical annual average.

Arup considers that the emission intensities calculated for both fuel types represent likely emissions intensity at theoretical maximum capacity and therefore may underestimate emissions intensity at typical annual average operation at a reduced capacity.

The materiality of the underestimate is not able to be determined without more detailed information relating to the operational efficiencies of the generators at reduced capacity.

3.2.2 Benchmarking

The GHG Assessment provides comparison against the NSW Greenhouse Gas Abatement Scheme Pool Coefficient for the purposes of comparing the project against the current NSW average. The limitations of this benchmark and the relative merits of other alternative benchmarks are discussed below.

NSW Greenhouse Gas Abatement Scheme

The GHG Assessment compares the predicted emissions intensity of the options against the NSW Pool Coefficient for 2009 which is currently estimated at 0.967 tCO2-e per MWh sent out. This includes both emissions from combustion of fuel as well as upstream fugitive emissions associated with fuel extraction (although upstream fugitive emissions are estimated to represent only around 3% of the value[15]).

The emission intensities for the Mt Piper options were recalculated by SKM with the GGAS methodology (not the NGERs Methodology) to give a like for like comparison. Using this methodology the GHG Assessment shows that both options for the Mt Piper Extensions are below the NSW Pool Coefficient. However, the NSW Pool Coefficient does not give a comparison to the current average for electricity generation in NSW.

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 emissions 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 (fired on distillate fuel) and thirteen existing hydro electric plants. Any new generators that have come on line or that will come on line since the inception of the Scheme in NSW are not deemed to be Category B Generators and therefore do not contribute to the pool coefficient[16].

The NSW Pool Co-efficient does not include electricity sourced from gas or 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 it is essentially 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 to represent the current NSW average emissions intensity of electricity generation may not be appropriate for comparative purposes.

[15] Calculated by Arup assuming all emissions are from coal fired generation with weighted emissions intensity of fugitive emissions of 3.67 kg CH4/tonne of fuel extracted and thermal efficiency of 0.39

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

NGA Factors

The NGA Factors document provides an emissions intensity per unit of electricity delivered to NSW consumers. In the most recent NGA Factors document this is determined as 0.89 t CO_2-e per MWh delivered. This factor is based on energy delivered to consumer *excluding* transmission and distribution losses and therefore is equivalent in emissions intensity per unit of energy sent out from generators. The NGA Factors value for emissions intensity of electricity delivered in NSW and can therefore be considered representative of the average emissions 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."*[17]

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 to represent the NSW current average emissions 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.

[17] Department of Climate Change and Water, National Greenhouse and Energy Reporting (Measurement) Amendment Determination 2009 (No.1) Explanatory Statement 1, Issued by the Authority of the Minister for Climate Change and Water, 1 July 2009 at 25

Therefore, it is considered that while the NGA Factors is indicative of the current NSW average emissions 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 emissions intensity is indicative of the average NSW emissions 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 emissions 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 2008/09;

E = the total electricity generated within NSW.

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 stationary energy emissions in NSW are the National Greenhouse Gas Inventory (NGGI) or data provided by 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[18] for the financial year 2007-2008. ESAA have published more detailed numbers for the financial year 2007-2008[19]. 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.

[18] ABARE, 2009, Energy in Australia 2009, Department of Resources, Energy and Tourism, pp22
[19] ESAA, 2009, *Electricity Gas Australia 2009*

A report by the Climate Group[20] has aggregated the AEMO (formerly NEMMCO) data and used emission factors for generators as published in an ACIL Tasman report[41]. 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 5 NSW Emissions and generation in 2008 (The Climate Group)

Sector	Emissions (million tonnes CO_2-e)	Generation (MWh)	Generation growth on 2007
Coal-fired generation	66,698	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.

[20] 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 6 Additional energy generation in NSW[21]

Additional electricity generation in NSW, post 2008	Additional capacity (MW)
CCGT planned	1220
CCGT (already built)	400
Sub critical coal planned	240
OCGT planned	3500
OCGT (already built)	640
Wind planned	2750
Biomass (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 emissions 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 calculation methodology assumes that that the annual average thermal efficiency is equal to the design efficiency. Notwithstanding, the annual average emissions intensity of the USC coal option is likely to be no more than the current average emissions intensity of electricity generation in NSW.

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

By the time the USC coal option would be built in 2015, the average NSW emissions intensity is likely to have reduced such that the USC coal option will have an emissions intensity greater than the average NSW emissions intensity at that time.

3.3 Comparison Against Total National Emissions

The GHG Assessment compares the annual average Scope 1 emissions of the Scope 1 annual average greenhouse gas emissions for two Mt Piper options against the current total national greenhouse gas emissions for the stationary energy sector and the total energy sector. In the GHG Assessment's analysis, the USC coal option is responsible for 3.65% of current total national emissions for the stationary energy sector and 2.61% of the total energy sector. Similarly the CCGT option is stated to comprise for 2.01% of current total national emissions for the stationary energy sector and 1.44% of the total energy sector. It appears that the GHG Assessment has drawn the values for total national emissions from the 2007 National Greenhouse Gas Inventory (with a slight discrepancy) which represents the most recent published values for emissions from the stationary energy and total energy sectors on an annual

[21] 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

basis. For the purposes of completeness, Arup has also calculated the percentage contribution to total annual national emissions (all sectors) as below.

Table 7 Comparison against National Emissions[22]

Sector	2007 National Emissions	% Contribution USC coal Option	% Contribution CCGT Option
Stationary Energy	291.7 $MtCO_2$-e	3.59%	1.97%
All Energy	408.2 $MtCO_2$-e	2.56%	1.41%
All Sectors (excluding LULUCF)1	541.2 $MtCO_2$-e	1.93%	1.06%

LULCF – Land Use, Land Use Change and Forestry

The use of 2007 national emissions data is considered appropriate and likely to provide a reasonable estimate of the percentage contribution of the facility to national totals in its first years of operation.

However the DGRs also require that total annual national emissions from the project are "*expressed as a percentage of the total national greenhouse gases produced per year over the life of the project*"

Over the life of the project, the "worst case scenario" for the project is if the Government passes the CPRS into law as proposed, meaning total national emissions will be 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 USC coal option and CCGT will emit a significantly larger proportion of national emissions.

According to the estimates of future National Emissions published by the Treasury[23] 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 USC coal and CCGT options' annual emissions to the total annual national emissions forecast under the CPRS 15 (15% reduction target by 2020) scenario is shown below:

[22] Australian national greenhouse accounts National Inventory Report 2007, Volume 1 http://www.climatechange.gov.au/publications/greenhouse-acctg/national-inventory-report-2007.aspx

[23] Treasury, 2008, *Australia's Low Pollution Future: The Economics of Climate Change Mitigation*

Table 8 Mt Piper 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[24]	530.8	100%
Mt Piper USC coal option 2015	10.47	1.97%
Mt Piper CCGT option 2015	5.76	1.09%[24]
Total Annual National Emissions 2044 - CPRS 15[24]	242.6	100%
Mt Piper USC coal option 2044	10.47	4.32%
Mt Piper CCGT option 2044	5.76	2.37%[24]
Total cumulative National Emissions 2015-2044 – CPRS 15[24]	10,870	100%
Mt Piper USC coal option cumulative 2015 - 2044	314.1	2.89%
Mt Piper CCGT option 2015 - 2044	172.8	1.59%

3.3.1 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[25] 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 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 Mt Piper Power Station Extension 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.

3.3.2 Comparison against Australia's Emission 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 there will be a minimum of 5% up to a maximum of 25% reduction on 2000 levels by 2020. The final targets are likely to be linked to international negotiations occurring later in 2009. To achieve the targets will require abatement of between 138 and 249 $MtCO_2$-e per year compared to business

[24] http://www.treasury.gov.au/lowpollutionfuture/spreadsheets/report_charts/Executive_Summary/Chart%201%20-%20Five%20pathways%20for%20Australian%20emissions%20and%20GNP.xls
[25] 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

as usual by 2020[26], while the project will increase national emissions by between 5 and 10 MTCo2-e according to the GHG Assessment.

The Project therefore represents a significant net increase in overall emissions. The USC 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 the greenhouse gas emissions as outlined in the GHG Assessment would represent approximately 2.9% (USC coal option) or 1.6% (CCGT option) of national emissions (all sectors) over the life time (assuming the CPRS is passed with a 15% reduction target by 2020 and an emissions reduction scenario that follows the CPRS 15 forecasts from Treasury).

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. Further, the emissions are considered significant in terms of increasing the overall abatement which must be achieved for Australia to meet its emission reduction targets and may potentially have an increase on the cost of the CPRS to the wider community.

[26] 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 emissions

4.1 Identification of measures

The GHG Assessment defines greenhouse gas management measures under the following categories:

1. Sequestration through carbon sinks
2. Carbon credit trading
3. Geosequestration
4. Renewable energy production

With the exception of geosequestration, the GHG Assessment discusses these measures in terms of offsite options to potentially offset greenhouse gas emissions rather than reduce on site emissions. The assessment provides a discussion of the mechanism of the offsets including their limitations validity of such offsets and does not specifically commit offsetting any emissions under these methods.

While concern about the use of offsets in the current political context may be valid, there is still scope to consider the use of renewable energy as on site option to directly displace electricity which would otherwise be produced by the CCGT or USC coal option. These technologies are discussed below:

Improved thermal efficiency

As stated earlier in Section 3.1.2, there may be options which have not been explored by the EA to improve thermal efficiency associated with plant configuration. While these may have some cost implications, they may be technically achievable and further may have an improved financial cost benefit under the proposed CPRS.

On-site wind

On site wind turbines could potentially be used to replace fossil fuel generators or to supply the auxiliary power requirements for the generators during times of high wind speeds. However wind turbines are not likely to materially contribute to energy generation at the Mt Piper site due to the predominance of light to moderate wind speeds (less than 3 m/s for around 70% of the time[27]) and are very unlikely to be financially viable.

Solar thermal augmentation

Solar thermal augmentation is a proven technology where solar power is used to augment the steam cycle. The use of solar thermal augmentation has not been considered by the EA Solar thermal augmentation is already installed at the Macquarie Generation coal fired power station at Liddell. According to Macquarie Generation[28] 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[29] and downward trends in capital costs[30] would suggest that solar augmentation could be capable of being

[27] SKM, 2009, Mt Piper Power Station Extension: Environmental Assessment, Appendix E – Air Quality Assessment, 18 September 2009
[28] http://www.macgen.com.au/News/2006News/LiddellSolarProjectUpdate.aspx
[29] MMA, 2009, *Benefits and Costs of the Expanded Renewable Energy Target*, Department of Climate Change
[30] Wyld Group et al, 2008, *High Temperature Solar Thermal Technology Roadmap*, NSW and Victorian Governments

comparable in cost and scale to carbon capture and storage and therefore warrants analysis.

Biomass co-firing

Another renewable energy augmentation that could be suitable for the Mt Piper USC coal 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. The GHG Assessment identifies that the Proponent is already adopting this technology at its existing Vales Point, Wallerawang and Mt Piper plants but does not discuss its applicability to the Mt Piper Extension. Macquarie Generation's power plants at Liddell and Bayswater also co-fire saw-mill residue and vegetable oil at a rate of 5% by mass or 2% by electricity sent out[31]. It therefore seems reasonable to assume this approach could be technically feasible and commercially viable for the Mt Piper USC coal fired option and warrants analysis.

Arup considers that the renewable energy augmentation measures to reduce and/or offset the greenhouse emissions identified in the GHG Assessment have not been adequately explored and have not been analysed in a transparent manner. Furthermore additional mitigation options (biomass co-firing), may be available to the project proponent at the commencement and throughout the life of the project.

All these options would likely result in some cost penalty in terms of cost per unit of energy sent out. However as these technologies are further developed, capital costs are likely to decrease such that they may become viable in the future if not at upon the commencement of operation. These trigger points should also be identified alongside the trigger points for carbon capture and storage (See Section 6).

4.2 Carbon Capture and Storage

The main management measure investigated by the GHG Assessment is carbon capture and storage. The GHG Assessment discusses the various options for CCS potentially available for the project and concludes that CCS "*is in the early stages of development and not commercially feasible for inclusion in the Mt Piper Extension at this time*". The assessment further proposes that the project is made "*capable of accepting carbon capture technology when it is feasible*".

To review these statements, Arup has provided a discussion of the various CCS technology including capture technology, transportation technology and storage technology and their technological maturity and application to the Mt Piper project.

The three components of CCS technology are in various stages of technological maturity and commercial readiness world wide as shown in Figure 1 below.

[31] Moghtaderi B., 2006, *Australian Bioresources*, BioResources 1 (1), 93-115

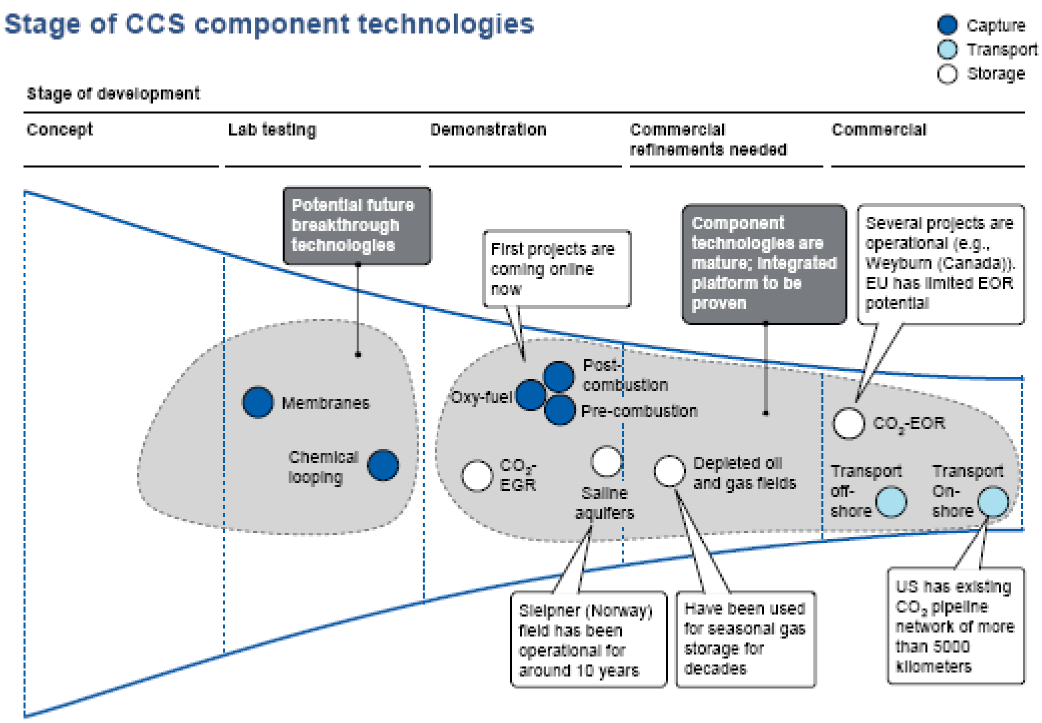


Figure 1 Stage of CCS Component Technologies

Source: McKinsey 2008[32]

It should be noted however, that the application of the transport and storage technologies above are specific to the project application. That is, transport infrastructure and storage facilities in commercial operation in other countries are not particularly relevant. Of greater importance is the status of the development of storage options and associated transport infrastructure in proximity to Mt Piper (See Section 4.2.2 and Section 4.2.3and below).

4.2.1 Capture Technology

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 Mt Piper USC coal or CCGT options. The GHG Assessment further states that only post combustion technology is applicable but gives no reason for this statement. However, it is acknowledged that based on current technologies both pre-combustion and oxy-fuel combustion technologies may be cost prohibitive as retrofit technologies.

The option of post combustion carbon capture with the use of chemical solvents (typically a form of amine) is presented as the most likely candidate for a future retrofit to the Mt Piper power plant. This technology has been technically proven and tested with a 90% collection efficiency, however is yet to demonstrate scalability to suit a 2000 MW coal or gas power generator. The technology also has large energy penalties on the power generator which impact significantly on the thermal efficiency of the generators. This is 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 and 15 percentage points[33] depending

[32] McKinsey Climate Change Initiative, 2008, *Carbon Capture and Storage: Assessing the Economics*, McKinsey & Company
[33] Based on information provided to Arup by technology suppliers and analysed by Arup CCS experts

on the age of the asset, power generator type, fuel properties and solvent technology adopted.

More promising post combustion capture technologies in terms of reduced energy penalties are emerging and include the chemical looping process. This application has the lowest energy penalty on the power generator of 7%[34], however the technology is still under pilot plant trials and some years away from being technical proven or demonstrated at a large scale.

It is important to note that the chemical solvent and chemical looping process are just two examples of potential technologies which may emerge as commercially viable options in the near future. To build a “carbon capture ready” plant would require the pre-nomination of a preferred technology. The two post combustion capture technologies discussed above will have completely different requirements for integration with the host power station due to completely different process properties. For example the solvent based solvent technology works at low temperature and low pressure whereas the looping technology operates at high temperature and high pressure. The solvent technology is also integrated downstream of the flue gas desulphurisation plant and requires a large footprint whereas the looping technology is integrated between the combustor and turbine expander and requires a smaller footprint.

4.2.2 Potential storage sites

The GHG Assessment identifies the Darling Basin as well as closer options in the Sydney and Gunnedah Basin as potential storage sites. The GHG Assessment provides a further summary of the current status of the Regional Stratigraphic Drilling Program which commenced in January 2009 including four investigation wells in the Sydney and Gunnedah basins, but states that data and recommendations will not be available until December 2009. The potential of the Sydney and Gunnedah Basin is therefore considered to be still under investigation at this stage.

Investigations within the Darling Basin, located more than 600km from the site are further progressed, but there is still no consensus on the suitability or the capacity of the basin as a storage site[35,36]

The figure below shows Australian basins and regions considered to have CO_2 storage potential. Significantly, the Sydney and Darling basin regions are denoted “yet to be assessed” according to the Cooperative Research Centre for Greenhouse Gas Technologies (CO_2CRC) [37.]

[34] Based on information provided to Arup by Mustang Engineering on the Calix calcium carbonate looping technology applied to a brown coal fired power station and analysed by Arup CCS experts
[35] FrOG Tech, 2007, Darling Basin Reservoir Prediction Study, NSW Department of Primary Industries
[36] Causebrook R, 2005. The Potential for Geological Storage of Carbon Dioxide in the Sediments of the Darling Basin (a re-assessment of the Darling Basin incorporating the results of the latest NSW-DPI databases and stratigraphic drilling), CO2CRC Report No. RPT05-0022. In, Innovative Carbon Technologies Pty Ltd (ICTPL), Final Report, Assessment of some potential CO2 storage areas Eastern Australian Sedimentary Basins, CD-05-008.
[37] 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

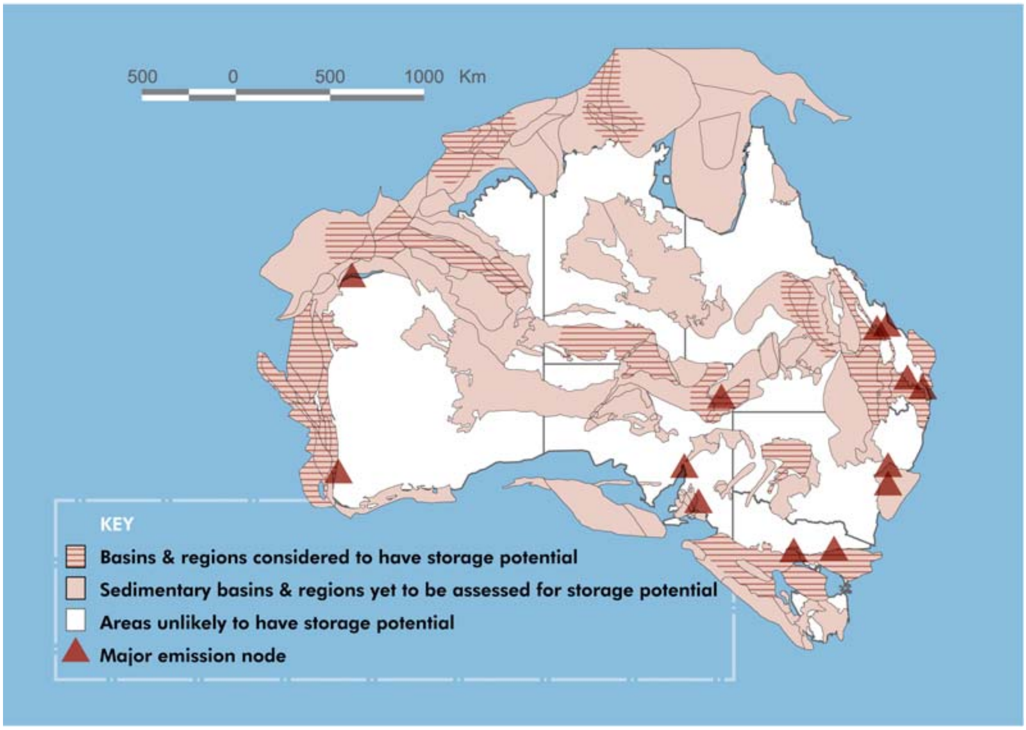


Figure 2: Australian basins and regions considered to have CO_2 storage potential
Source: Cooperative Research Centre for Greenhouse Gas Technologies (CO2CRC)

4.2.3 Transport technology

While the transportation technology is well understood and technically mature, the viability of the transportation will depend upon the distance and therefore the energy requirements for compression along the total pipeline length. The viability of the transportation therefore depends upon the identification of a storage site in close proximity to the generation plant. The GHG Assessment discusses a pipeline from the site to the Darling Basin which has been investigated by Worley Parsons on behalf of Macquarie Generation[38]. The GHG Assessment states "*that the final route selection will be subject to the outcome of the exploratory drilling program and may be significantly shorter if large scale storage is available in the Gunnedah basin"*. This report estimated the cost of the pipeline at between around $1.5 and $5.5 billion for a 632km pipeline.

Arup considers that it should also be noted that the pipeline could also be significantly longer if large scale storage is not available in the Darling Basin.

4.2.4 Carbon Capture ready

CCS does not form part of the Mt Piper Extension proposal, nevertheless the GHG 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.

The IEA[39] defines carbon capture ready as:

> *"a plant which can include CO2 capture when the necessary regulatory or economic drivers are in place. The aim of building plants that are capture ready is to reduce the risk of stranded assets and 'carbon lock-in'.*

[38] Worley Parsons, 2007, *Geosequestration Compression and Pipeline Study*, Macquarie Generation

[39] IEA Greenhouse Gas R&D Programme, 2007, CO2 Capture Ready Plants <www.iea.org/papers/2007/CO2_capture_ready_plants.pdf>

Developers of capture ready plants should take responsibility for ensuring that all known factors in their control that would prevent installation and operation of CO2 capture have been identified and eliminated.

This might include:

- *A study of options for CO_2 capture retrofit and potential pre-investments*
- *Inclusion of sufficient space and access for the additional facilities that would be required*
- *Identification of reasonable route(s) to storage of CO_2*

Competent authorities involved in permitting power plants should be provided with sufficient information to be able to judge whether the developer has met these criteria."

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 measures to make a power plant carbon capture ready have been acknowledged, further investigations particularly related to the storage of CO_2 and potential pre-investments would be required prior to approval of the final Project Application.

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 Proponent to lock in a technology at the time of detailed design. From the GHG Assessment this appears to be chemical solvent 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.

A risk averse approach to carbon capture readiness may be to incorporate provisions suitable for other technologies that do not diminish the opportunities for chemical solvent based post-combustion carbon capture and storage.

Arup considers that the viability of CCS for the Mt Piper Extension is uncertain and is likely to depend on the outcomes of the assessments of the Sydney-Gunnedah Basin and Darling Basin as potential storage sites.

Further, aside from allocating additional site area, the project may not be able to be made Carbon Capture Ready to significantly reduce retrofit costs at this point in time without locking in a particular capture technology (which has risks if a different, more efficient technology emerges).

5 Evaluation of the project under the CPRS

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

5.1.1 Evaluation without mitigation measures

The GHG Assessment evaluates the financial impact of the prescribed carbon prices ($10, $25 and $50 per AEU) for each of the proposed coal and gas options in terms of the additional cost per MWh sent out above the current costs of generation. No mitigation measures are considered in the carbon price assessment with the exception of CCS.

The additional cost for USC coal and CCGT presented in the GHG Assessment as a result of the carbon price appears to have been determined by multiplying the Scope 1 emission intensities calculated in preceding chapters (in tCO2-e per MWh sent out) by the relevant carbon price. It is therefore unlikely that the cost impacts include any increased upstream costs of fuel associated with a carbon price of Scope 3 emissions which is likely to be passed on to some extent from the fuel suppliers to the generators.

Further, the cost of carbon for the USC coal and CCGT options is presented as an additional cost per unit of generation. While this is useful in determining the absolute impact for each option, it does not allow the project to be ‘evaluated’ in terms of the impact of the CPRS on either option’s viability. It would be more useful to compare the total costs of generation in terms of long run marginal costs (LRMC) of both options to the current and projected costs of other generation technologies to evaluate the financial viability of both options in the future.

> 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.

5.1.2 Evaluation with Mitigation Measures

The GHG Assessment provides no evaluation of mitigation measures other than CCS. The use of LRMC as discussed above would also enable evaluation of other mitigation measures including renewable energy augmentation and biomass co-firing.

The GHG Assessment provides some analysis of CCS and its viability under various carbon prices by comparing:

- the additional cost per unit of electricity sent out under the three carbon prices without mitigation; with
- the additional cost of the CCS technology retrofit per unit of electricity sent out.

The inference of the GHG Assessment is that when these two values become equal, then the CCS becomes viable as a mitigation measure. Based on this methodology, the GHG Assessment concludes that CPRS costs of less than $50 per tonne would be insufficient to support the retrofit.

However, the methodologies used to produce these two values for comparison are incompatible. The “without mitigation” options analysis is simply a carbon price multiplied by the emissions intensity while the CCS analysis is based on a complex analysis of the weighted average cost of capital, financing costs etc for a representative new build coal fired power plant in Europe. Due to incompatibility of these methods, the evaluation of the CCS mitigation option under the various carbon prices is not considered to be technically adequate.

The CCS costs assumed for 2020 and 2030 are based on values published by McKinsey in 2008[40] for two scenarios:

- €35-€50 (AUD$60-80) per tonne of CO_2 abated for early commercial scale CCS projects on new coal fired power stations; and
- reduced to €30-€45 (AUD$50-70) per tonne of CO_2 abated by 2030 due to operating and scale effects.

These cost estimates produced by McKinsey include capture, transportation and storage but are explicitly specific to the new build coal and the European case as stated in the report disclaimer. For the retrofit case, there are likely to be significant additional costs above those for a new build plant fully equipped with CCS. McKinsey 2008, specifically states the following four factors which are likely to drive the cost increase for retrofits:

- Higher capex of the capture plant;
- Existing plant configuration and space constraints;
- Shorter lifespan (reducing the "efficiency" of the initial capex); and
- Higher energy efficiency penalty compared to fully integrated new-built CCS plant.

Even for a "carbon capture ready" plant, all of these factors are likely to apply to some extent. Most importantly is the shorter lifespan of the plant. If CCS is not installed until well into the project's lifespan it will likely have increased weighted average cost of capital which will impact significantly on the levelised costs produced by McKinsey.

Further, the McKinsey costs assume that the CO_2 is transported no more than 200km on shore or 300km offshore and states that "*costs for projects –such as those with larger transport distances – may even fall outside of this range*".

It is therefore considered that the CCS costs may have been underestimated implying that CCS may not be viable until a higher carbon price than implied by the GHG Assessment is in place.

Arup therefore considers that the CCS costs produced by McKinsey 2008 may underestimate the cost of CCS for the Mt Piper options, implying that CCS may not be viable until a higher carbon price than implied by the GHG Assessment is in place.

Overall Arup considers that evaluation of the project under the CPRS is not technically adequate in that it does not evaluate the project under different carbon prices and only evaluates the viability of CCS. Further the methodology to assess the project without CCS under a carbon price and the methodology to assess the project with CCS are not compatible and therefore a comparison is not considered appropriate.

Arup considers that the CPRS is likely to have several impacts on the project and potential mitigation options. As an indication of what a thorough analysis of these

[40] n 32

impacts could look like, Arup has compared estimates of LRMC for different generation technologies and mitigation measures under the different AEU price signals.

The following figures show an indicative LRMC of the impact of the DGR determined AEU price signals. The base LRMC figures for USC, CCGT with CCS are based on analysis for new entrant power plants in NSW in 2015 calculated within a report by ACIL Tasman[41] . 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[42].

Figure 3 Indicative LRMC excluding carbon price

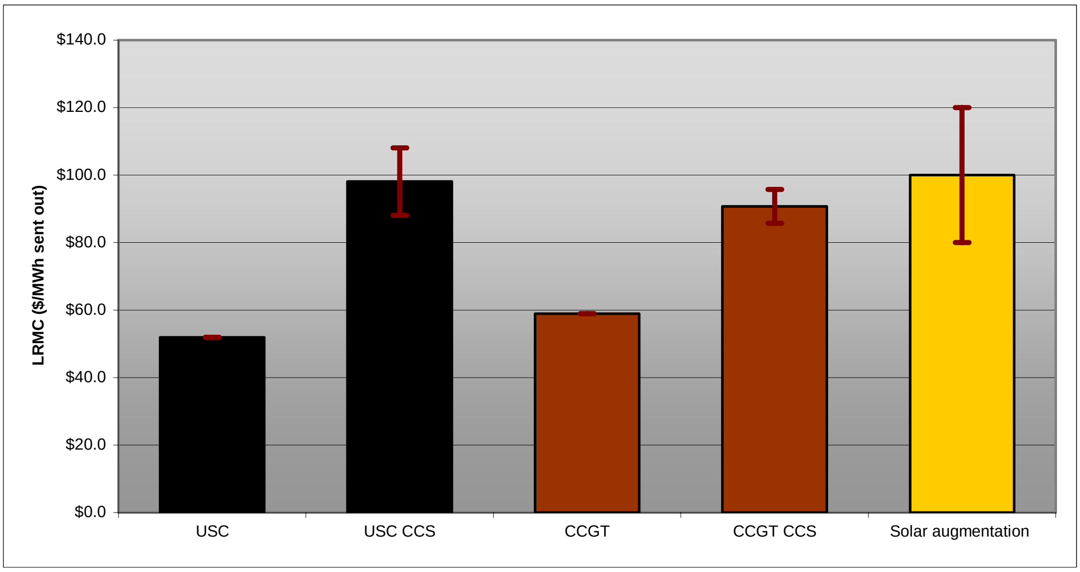
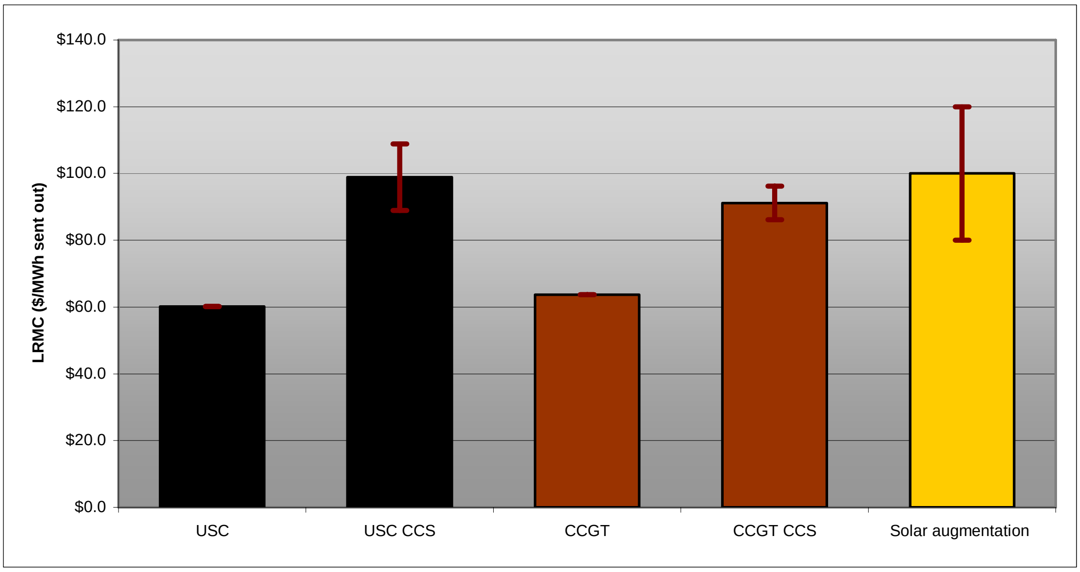


Figure 4 Indicative LRMC with $10/t AUE price



[41] ACIL Tasman, 2009, *Fuel resource, new entry and generation costs in the NEM*, prepared for the Interregional Planning Committee

[42] Wyld Group et al, 2008, *High Temperature Solar Thermal Technology Roadmap*, NSW and Victorian Governments

Figure 5 Indicative LRMC with $25/t AEU price

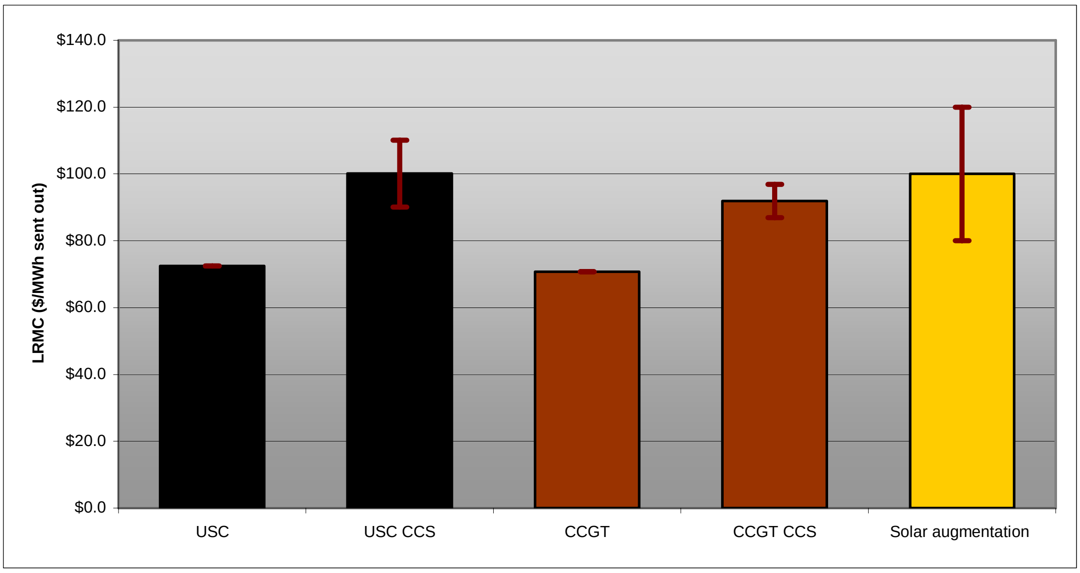


Figure 6 Indicative LRMC with $50/t AEU price

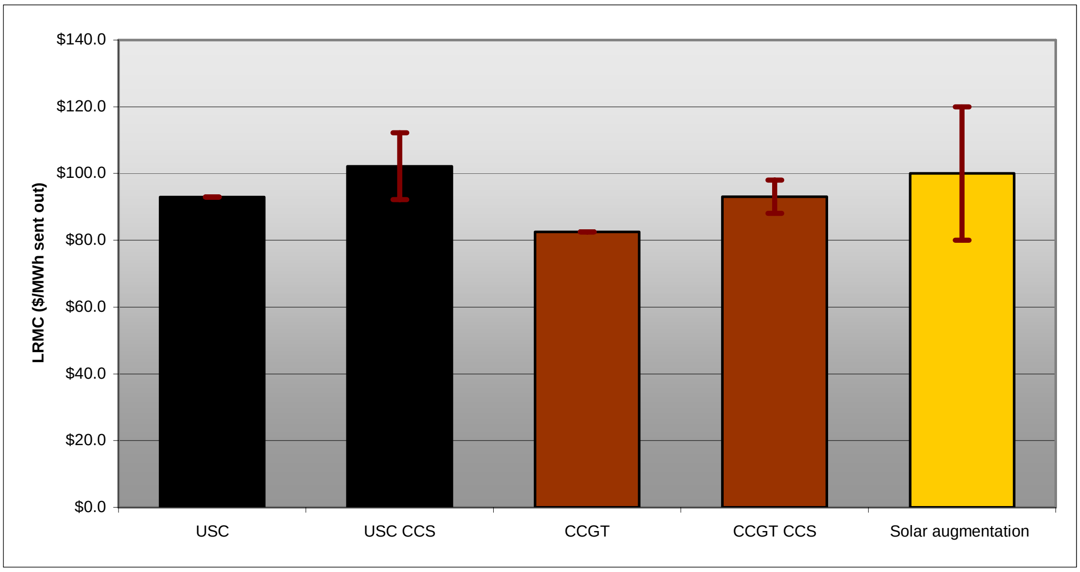


Figure 4 to Figure 6 above are included for indicative purposes only, they show that the CCGT option becomes more viable than the USC coal option at a carbon price of between $10 and $25 per tonne. They also show that solar augmentation may be just as viable as CCS technology. These conclusions are based 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.

The Federal Government has made a large amount of information about the scheme and the economic forecast modelling freely available to the public which could be used to model the fluctuations in the carbon price. 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[43].
- AEU carbon prices are expected to be $10 in July 2011[43], $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) [44].
- 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[45].

This information could be used to evaluate the LRMC of the project options under the CPRS in order to determine the likely best option from an economic perspective over the life of the project. This sort of analysis has been included in Arup's recommendations in Section 6.

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

[43] http://www.climatechange.gov.au/emissionstrading/timetable.html
[44] http://www.treasury.gov.au/lowpollutionfuture/spreadsheets/report_charts/Chapter%206/Chart%206.3%20-%20%20Australian%20emission%20price.xls
[45] http://www.climatechange.gov.au/emissionstrading/legislation/pubs/coal-fired_electricity_generation.pdf

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 Concept Plan approval, project 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 (for both the Concept Plan and final project), 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 Approval

Prior to project approval 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)
    - o CCS retrofitted at earliest point in time when it is considered likely that storage location is identified and pipeline constructed
    - o CCS retrofitted at nominal periods from this time over the life of the facility
- CCGT

[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.

- CCGT retrofitted with integrated CCS at a later date (up to theoretical maximum % capture)
    - 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 Magasanik 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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