



Community Consultation

Appendix

B

Munmorah Power Station Rehabilitation



BACKGROUND

Concept approval for the proposed rehabilitation of the Munmorah Power Station is being sought as part of the NSW Government's Energy Reform Strategy. The Strategy will help secure future electricity supplies and economic growth by encouraging private sector development of new base load generating capacity.

There are three potential sites for new base load power stations that are currently Government owned. These are Bayswater B, owned by Macquarie Generation, and Mt Piper Extension and Munmorah Rehabilitation, both owned by Delta Electricity. In keeping with the NSW Government's "fuel neutral" policy, new power stations on these sites can use either/or both gas and coal.

Due to the long time frames involved in planning and constructing new sources of electricity, it is necessary for the planning process to begin now.

Munmorah Power Station is located in the Tuggerah Lakes catchment on the NSW Central Coast near Budgewoi.

Munmorah currently produces electricity using pulverised coal-fired boilers and steam driven turbo-generators. It originally comprised four 350 MW generating units (1,400 MW total capacity) which were progressively commissioned between 1967 and 1969.

Units 1 and 2 were decommissioned in 1996. Units 3 and 4 have remained in service, generating electricity as required. In the absence of significant rehabilitation, the power station was due to cease operating within five years.

The site is a valuable power generation site for NSW due to its established connections to the transmission system, a cooling water system which makes use of the water in Tuggerah Lakes, along with other associated infrastructure.

When it was built in the 1960s the power station used up to date technology in its design construction and operation. Since that time, power station design and associated technologies have made major advances. Some of these advances, such as the replacement of electrostatic precipitators with fabric filters that virtually eliminate visible emissions from the stacks, have already been incorporated into the power station.

THE PROPOSAL

Delta Electricity is now seeking to obtain approvals for the rehabilitation of Units 3 and 4, which would replace components



External view of Turbine Hall

with the most technologically advanced equipment. The rehabilitation will improve the reliability, efficiency and environmental performance of the generating units and return output to the original 350 MW capability.

Importantly, these improvements would enable the power station to continue to generate electricity in the short to medium term (up to 20 years) while reducing the greenhouse footprint per unit of electricity generated.

Recognising the environmental benefits of low emission gas as a fuel source, the rehabilitation will also make provision to use gas as fuel, either in combination with coal or as a replacement. This flexibility of fuel source would provide for changes in the availability of gas and emerging market demands.

A rehabilitated Munmorah Power Station will also provide for carbon capture and storage technology installation once it becomes commercially viable.

ENVIRONMENTAL ISSUES

A Preliminary Environmental Assessment (PEA) has been undertaken by Delta Electricity to identify potential environmental issues associated with the proposal. The Department of Planning will now consider what further investigations are required to support the proposal.

The project will result in improved station performance and life extension of existing infrastructure. The environmental impacts of the rehabilitated power station will be potentially less than the impacts from the currently operating approved and licensed power station.

The improved efficiency of the power station would result in a reduction in coal consumption per unit of energy generated and reduced greenhouse emissions per unit of energy generated.

Many aspects of the power station operations, such as the fabric filters, flue gas and cooling water systems, will not be affected by the proposed rehabilitation. Accordingly, the environmental impacts associated with these aspects would be the same or less than approved for current operations.

Careful planning, implementation and monitoring of a construction environmental management plan would ensure that impacts during the rehabilitation works are effectively managed.

THE ASSESSMENT PROCESS AND COMMUNITY INPUT

The proposal to rehabilitate the Munmorah facility is subject to State planning requirements and the approval processes for major infrastructure projects. Delta Electricity has lodged a project application

with supporting documentation for the proposed rehabilitation with the Department of Planning to assess the proposal under the provisions of Part 3A of the Environmental Planning and assessment Act 1979.

The Department of Planning will now consider the environmental implications of the project and is expected to issue the requirements for an Environmental Assessment (EA) under Part 3A of the (EP&A) Act. Once completed, the Environmental Assessment will be exhibited for public comment by the Department of Planning.

CONSULTATION

Delta Electricity welcomes comments from the community and consulting with the community is a vital part of the environmental assessment process. If you would like to find out more, provide comments or be placed on the mailing list for the project, please contact by email to:

munmorahrehabilitation@de.com.au

by phone on 1800 057 630

by fax on (02) 9465 5881

or write to

Munmorah Rehabilitation Project

Aurecon Australia Pty Ltd,

Level 2, 116 Military Road

Neutral Bay NSW 2089

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Munmorah Power Station Rehabilitation

The NSW Government's Energy Reform Strategy is designed to help secure affordable electricity supplies, and economic growth, by encouraging private sector investment in the development of new base load power generation.

Government owned generators currently own three potential sites for new base load power stations. These are Macquarie Generation's Bayswater B in the Hunter Valley, and Delta Electricity's Mt Piper Extension site near Lithgow and the Munmorah Rehabilitation project on the Central Coast. Consistent with the NSW Government's "fuel neutral" policy, new power stations on these sites can use either/or gas and coal.

Due to the long time frames involved in planning and constructing new sources of electricity, it is necessary for the planning process to begin now. It is in this context that a Major Project Application and Preliminary Environmental Assessment for the rehabilitation of the Munmorah Power Station has been lodged with the Department of Planning.

What's the proposal?

The proposed rehabilitation of Munmorah Power Station involves the replacement of obsolete components in Units 3 and 4 of the power station with the best available technology. The rehabilitation will improve the reliability, efficiency and environmental performance of the generating units and return each unit's output to its original 350 MW capability. It will also provide for the installation of carbon capture and storage technology when it becomes commercially available.

A comprehensive environmental assessment as outlined in the preliminary environmental assessment, will be undertaken in line with the requirements of the Department of Planning. Once completed, the Environmental Assessment will be exhibited for public comment by the Department of Planning.

Delta Electricity welcomes comments from the community.

Community and other stakeholders are encouraged to provide feedback as part of the environmental assessment process. To view the preliminary environmental assessment and a community newsletter about the project, click on the relevant link:

[Preliminary Environmental Assessment – Munmorah Rehabilitation](#)

[Community Newsletter – Munmorah Rehabilitation, July 2009](#)

To contact the project team or to make a comment:

Call the toll free information line- 1800 057 630

Send an email to: munmorahrehabilitation@de.com.au

The applications include proposals for:

- 1) **New 2000MW gas or coal-fired baseload power station adjacent to the existing Bayswater Power Station in the Hunter Valley;**
- 2) **New 2000 MW gas or coal-fired baseload power station adjacent to the existing Mount Piper Power Station in the state's Central West;**
- 3) **The rehabilitation of 700MW of generating capacity at the Munmorah Power Station on the Central Coast, including potential gas-firing to minimise coal use and greenhouse gas emissions.**

Mr Tripodi said the NSW Government will ensure developers of the new power stations include provisions for best available technology such as the installation of Carbon Capture and Storage (CCS) when it becomes commercially available.

“The NSW Government is already well down the path to a low carbon future, with major investment in energy efficiency through the NSW Energy Efficiency Strategy and a strong focus on increasing the State's renewable energy mix.

“We are committed to keeping NSW at the forefront of efforts to improve the greenhouse performance of the nation's power industry.

“Today we have begun the planning process to build the next generation of baseload power stations.”

Mr Tripodi said the estimated value of the three projects is in the range of \$6 billion to \$10 billion and would generate more than one thousand construction jobs.

The Department of Planning's formal process has now commenced and details of the proposals and the Director General's requirements for the forthcoming Environmental Assessment phase would soon be available on the NSW Department of Planning's website www.planning.nsw.gov.au.

The Minister said the Major Project Applications were eligible for consideration as critical infrastructure under Part 3A of the Environmental Planning and Assessment Act.

“Thorough planning and environmental assessments and public consultation will apply throughout all stages of the approval process,” Mr Tripodi said.

Media Contact: Brad Schmitt (02) 9228 5451 or 0407 995505



THE HON. JOE TRIPODI MP
MINISTER FOR FINANCE
MINISTER FOR INFRASTRUCTURE
MINISTER FOR REGULATORY REFORM
MINISTER FOR PORTS AND WATERWAYS

M E D I A R E L E A S E

NSW looks to cleaner, greener power stations

July 2, 2009

NSW Finance Minister Joe Tripodi today announced applications have been lodged with the Department of Planning for potential gas-fired baseload power stations on sites previously earmarked for coal-fired generators.

The Major Project Applications for three “dual fuel” power station sites will give private investors the option of using gas or coal-fired technology or, a combination.

“With the prospect of carbon pollution pricing, gas will become an increasingly attractive fuel source for future base-load generation,” Mr Tripodi said.

“The Rees Government is preparing for the next generation of baseload power stations using more environmentally friendly gas-fired technology.”

Mr Tripodi said the 2007 Owen Inquiry determined NSW needed to be ready for new sources of baseload electricity by the middle of the next decade.

“This means it is imperative to start the planning process for new power stations now to ensure all options remain on the table.

“The potential development of these power station sites is part of the Government’s Energy Reform Strategy which will help secure NSW’s future electricity supplies for decades to come,” Mr Tripodi said.

“As we transition towards a low carbon economy, the Government is creating a platform to secure our energy needs and look after the environment.

“Whichever fuel source is ultimately used by the developer these new stations will use the cleanest, greenest commercially-available and viable technology which will lead to a reduction in the intensity of greenhouse gas emissions.”

Mr Tripodi said the planning applications have been lodged to prepare the development sites for sale to the private sector.

“Our electricity reform program is designed to deliver new investment in power stations to help drive our economy and secure future investment and jobs and this is a critical milestone towards achieving that goal.”



**Technical Investigations
Gas Firing**

Appendix C

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1. Feasibility of Gas Firing

As the proposed Munmorah rehabilitation will allow for potential gas firing, an investigation has been conducted into the technical feasibility of co-firing varying proportions of natural gas with coal into the existing boilers. As natural gas has significantly different combustion characteristics and radiative heat transfer characteristics to coal detailed simulations of furnace and boiler performance were conducted. The following sections describe the approach taken, assumptions and results of a series of boiler computational simulations conducted using the PROATES boiler modelling package.

1.1 PROATES Model

PROATES (PROcess Analysis for Thermal Energy Systems) is a whole plant modelling package for analysing and improving power plant steady state thermal performance. It contains modules representing the physical processes of individual plant components, linked together to make a mathematical model. The software is proprietary to E.ON (UK) (formerly Power Gen) and has been under continuous development since 1979. E.ON has extensively validated the software against real plant data.

Each module represents a section of the boiler (e.g. convective superheater). A module consists of a set of formulations which represent the physics and mass, momentum and energy transfers between the inputs and outputs, (such as water/steam, gas, and heat/power), of a particular item of plant.

Heat transfer to tube banks is determined via calculation of an overall heat transfer co-efficient. This co-efficient is the sum of:

- i) Gas side convection co-efficient
- ii) Gas side radiation co-efficient
- iii) Water/ steam side heat transfer co-efficient
- iv) Conduction across the base tube
- v) Thermal resistance of fouling deposits on tubes.

Items (i), (ii), (iii) & (iv) are computed explicitly for each section of the boiler to enable steam conditions to be predicted based on gas side temperatures and flows. The thermal resistance or fouling factor (v) can therefore be used to tune model predictions to measured boiler performance to account for coal heat transfer characteristics. PROATES can be used to analyse and optimise current plant performance, to identify remedial options for improving performance and to study new plant options.

1.2 Modelling Approach

An existing PROATES model of a Munmorah boiler was used to assess coal/gas co-firing and gas only firing. While the model has been shown to predict reasonable outcomes it has not been rigorously validated due to a lack of reliable data for calibration and verification. For further information refer to Aurecon (Connell Wagner) report to Delta Electricity "Preliminary Report, Thermal Performance Modelling of Munmorah Units 3 and 4" dated 17 June 2008.

The modelled main steam and reheat steam flow rates were held constant at the original turbine design flow rates for 350 MW generated output. The design flow rates are 293 kg/s and 226 kg/s for main and reheat flows respectively (refer to Munmorah Heat Balance Diagram MM235964). The base model (100% coal) predicts that design main steam temperature of 566°C can be attained with moderate desuperheater spray flow. Hot reheat steam temperature is predicted to be 524°C which is 14°C below design at 538°C. These predictions are based on a number of assumptions including bottom four mills in service (Mills ECDB), burner tilt at zero degrees and flue gas oxygen at economiser exit of 3.2% dry basis.

As the hot reheat temperature is deficient compared to design, actual Unit output will be somewhat less than design load at 350 MW. Under actual operation this may be compensated for by firing harder to increase steam flow sufficient for 350 MW. As stated above model steam flows are held constant for all '350 MW' scenarios and the adequacy of boiler performance is assessed by comparing predicted steam temperatures to design steam temperatures.

The base model was modified to burn gas as well as coal. The gas proportions considered were 25%, 50%, 75% and 100% on a fuel energy input basis.

1.3 Assumptions

In establishing the PROATES model a number of assumptions were made regarding the boiler, coal properties and required steam conditions. These are summarised below.

1.3.1 Boiler

Table 2.1 summarises the assumptions made in establishing the boiler model:

Table 2.1 Boiler assumptions

Parameter	Units	Value
Flue gas O ₂ :		
coal only	% dry basis	3.2
coal and gas		2.4
gas only		1.6
Fuel Input Temperature	°C	20
Mean Temp of Ash Lost	°C	600
Ash carried over (fly ash fraction)	-	0.85
Carbon in ash	%	2

Table 2.2 Munmorah Rehabilitation Coal Properties (refer Delta email 3 Jul 2009)

Coal Properties	Units	Values
Gross SE	MJ/kg ar	21.7
Ash	% ar	24
Moisture	% ar	9.8
Ultimate Analysis		
Hydrogen	% daf	4.8
Oxygen	% daf	12.5
Nitrogen	% daf	1.9
Sulphur	% daf	0.6
Carbon	% daf	80.2

Table 2.3 Munmorah Rehabilitation Gas Properties

Gas Properties	Units	Value
Gross SE	MJ/kg	51.6
Fraction by weight CH ₄	-	0.853
Fraction by weight C ₂ H ₆	-	0.082
Fraction by weight CO ₂	-	0.053
Fraction by weight N ₂	-	0.012

1.3.2 Fuel Properties

Delta Electricity provided projected coal properties for the rehabilitation project. These properties are summarised in Table 2.2.

'Natural Gas' was assumed to have the properties as provided in Table 2.3.

1.3.3 Turbine Inlet Steam Conditions

Aurecon has assumed that the Munmorah steam turbines will be rehabilitated to at least the original design performance of the turbines. For the current work the design parameters for the original turbine included in Table 2.4 have been used. The PROATES model used these conditions as a basis for the boiler calculations. In particular, the model maintains the design steam flows and computes the resultant steam temperatures.

Table 2.4 Original turbine design conditions (reference drawing MM235964)

Parameter	Units	Value
Main steam		
Pressure	bar-abs	159.48
Temperature	°C	566
Flow	kg/s	293
Reheat steam		
Cold Pressure	bar-abs	42.01
Hot Pressure	bar-abs	37.73
Cold Temperature	°C	370
Hot Temperature	°C	538
Flow	kg/s	226
Final feedwater		
Pressure	bar-abs	190 – assumed
Temperature	°C	252
Flow	kg/s	293

Table 2.5 Summary of PROATES predictions

Parameter	Units	Gas input energy				
		0%	25%	50%	75%	100%
Coal input energy	%	100%	75%	50%	25%	0%
Main steam flow	kg/s	293	293	293	293	293
Main steam temp.	°C	566	566	566	566	456
Hot reheat steam temp.	°C	524	522	523	525	464
Desuperheater spray flow	kg/s	15	12	12	13	0
Flue gas O ₂ at Econ O/L	%	3.2	2.4	2.4	2.4	1.6
Fouling resistance	m ² K/kW	6	6	6	6	0.5
Furnace exit gas temp.	°C	1285	1297	1301	1308	1037
Air heater exit gas temp.	°C	118	117	117	117	107

1.4 Results

Simulations were conducted of the five gas / coal scenarios described above. Table 2.5 summarises selected PROATES predictions which are discussed in the following paragraphs.

The model predicts little change in plant thermal performance for 25%, 50% and 75% gas compared to coal only. In all cases design main steam temperature (566°C) is achieved with desuperheater sprayflow similar to the 100% coal scenario. As mentioned earlier, for 100% coal, the model predicts a shortfall in hot reheat steam temperature compared to design at

538°C. This is also the case with the gas co-firing. If design hot reheat steam temperature is required then modification of boiler heating surfaces is required for both 100% coal and co-firing cases. Furthermore, modification of the turbine design will likely impact on reheater thermal duty, due to a possible change in cold reheat temperature.

Coal firing results in ash deposits coating or fouling the heat transfer surfaces causing a reduction in heat pickup by the water and steam. For natural gas firing the boiler is expected to operate in a relatively clean condition with lower fouling factors. For gas firing the

fouling factor is typically 0.5 m²K/kW compared to 3 to 7 m²K/kW for coal.

Key to the predicted outcomes for co-firing is the assumption that the fouling resistance expected with 100% coal will not change for co-firing. This cannot be predicted with certainty. Provided the fouling assumption is correct no additional modifications are required to boiler heat transfer surfaces for co-firing.

For the 100% gas case the fouling factor was reduced from 6 to 0.5 m²K/kW. This resulted in a significant drop in main and hot reheat steam temperatures. The relatively clean furnace more readily picks up heat resulting in a reduction in firing rate to achieve the target evaporation rate (293 kg/s). The energy remaining in the flue gas is insufficient to attain the target steam temperatures. Essentially, a clean Munmorah furnace is too large for 100% gas firing. Modelling lower load indicates further decrease in steam temperature. Gas fired only operation without boiler modification is not recommended.

Potential boiler modification to allow 100% gas only operation are waterwall surface area reduction and/or application of a thermal barrier on the waterwall. Waterwall surface reduction would require removal of a significant portion of the furnace. It may be possible to remove the top section including burner levels. Gas burners may be placed in the new roof. The steam drum would also need to be lowered. In Aurecon's experience it is difficult to obtain manufacturer support for an insulating barrier solution. Aurecon is not aware of any actual cases of significant heat transfer adjustment via thermal barrier. If the Munmorah boilers were modified for 100% gas firing they would no longer be suitable for coal firing.

At this stage 100% gas firing is not considered to be viable.

1.5 Modifications Required for Co-firing

For either 100% coal or co-firing, reheater performance requires improvement to regain the shortfall in hot reheat temperature. This situation may be exacerbated should a new turbine provide cold reheat steam at a lower temperature than the current design. It is understood that the reheater is already included in the rehabilitation workscope.

For the purpose of this high level study, it has been assumed that natural gas would be available at the boundary of Munmorah at mains pressure. The pressure will be let down through a pressure reducing

station after being heated in a bath. The system requires the following components for gas co-firing:

- **Gas burners:** Gas burners are to be installed together with their detection and monitoring systems and equipment required for integration into the ICMS. At this stage we propose that the existing eight oil ignitors per boiler be replaced with gas burners. We assume that if gas co-firing is adopted that gas would always be available negating the need for ignition oil. Based on information from one equipment supplier it may not be possible to obtain suitable burners to fire 75% gas through eight burners only. For eight burners only it may be prudent to trim the maximum amount of gas back to say 65%.
- **Gas Reticulation Piping:** Piping is to be provided from the boundary to the Water Bath Heater and the pressure Reducing Station and thereafter to reticulate gas to individual burners on the boiler.
- **Natural Gas Fired Water Bath Heater:** A water bath heater has been selected to heat the gas prior to expansion so that the Joule-Thompson effect is countered. The Joule-Thompson effect describes the temperature drop due to the pressure drop that occurs when gas expands rapidly in a pipeline. The Joule-Thompson effect is particularly pronounced in the expansion from mains pressure to power station gas operating pressure, because of the large pressure differential and the short distance within which the expansion takes place. Very cold gas has to be avoided because of the impact of valve freezing on system operation.
- **Pressure Reducing Station:** A pressure reducing station has been selected to reduce the pressure from the relatively high mains pressure to that of the power station gas operating pressure. The pressure reducing station regulates the delivery pressure to the power station so that the system components are protected from overpressure and pressure fluctuation.

2. Predicted Performance, Efficiency and Emissions

2.1 Thermal Performance

The original design performance and performance test results are summarised in Table 3.1. The 1969 test results show that when the plant was new, the design performance levels could not be achieved. The

December 2006 test results show that a further deterioration in performance occurred over the intervening decades. A significant reason for the reduced performance levels is the change in turbine heat rate - a 14% higher heat rate was measured in 2006 compared to the original design.

Table 3.1 Original design and estimated test performance

Parameter	Units	Original Design	Test 5S 9 Sep 69	WP Test 13 Dec 06
Unit load	MW-Gen	350	348	290
Coal input energy	%	100	100	100
Main steam T.	°C	566	561	-
Hot reheat steam T	°C	538	540	-
Coal flow	kg/s	40	43	39
Coal rate	t/GWh-Gen	416	442	488
Flue gas O ₂	%	3.2	3.2	3.2
Boiler efficiency	%	88.9	88.8	88.8
Turbine heat rate	kJ/kWh	8109	8563	9244
Turbine efficiency	%	44.4	42.0	38.9
Unit efficiency (gen)	%	39.5	37.3	34.6

Table 3.2 Predicted performance for proposed rehabilitated Units

Parameter	Units	Predicted Performance					
		350	350	350	350	350	280
Target load	MW-Gen	350	350	350	350	350	280
Gas input energy	%	0	25	50	75	100	0
Coal input energy	%	100	75	50	25	0	100
Main steam T.	°C	566	566	566	566	566	563
Hot RH steam T.	°C	524	522	523	525	529	496
Natural gas flow	kg/s	0.0	4.3	8.6	13.1	17.6	0.0
Coal flow	kg/s	40	31	21	10	0	34
Coal rate	t/GWh-gen	416	316	214	108	0	439
Flue gas O ₂	%	3.2	2.4	2.4	2.4	1.6	3.2
Boiler efficiency	%	88.9	88.8	88.3	87.7	87.2	88.5
Turbine heat rate	kJ/kWh	8109	8109	8109	8109	8109	8230
Turbine efficiency	%	44.4	44.4	44.4	44.4	44.4	43.7
Unit efficiency - gen	%	39.5	39.4	39.2	38.9	38.7	38.7

Table 3.2 summarises the predicted thermal performance for the 5 scenarios considered in Table 2.5. The predicted performance assumes full load operation and as new condition. A sixth scenario for 80% load (280MW) has also been included in Table 3.2. This scenario may be used to approximate annual performance at 80% capacity factor. Actual performance at 80% capacity factor will depend on output factor and plant condition.

In making these predictions the following assumptions were made:

- The same 'rehabilitation' coal was used for all predictions including actual tests.
- Auxiliary energy is 5% of generated (refer WP Stage 2 Report Appendix 3).
- 13 December 06 Test estimate based on WP Stage 2 Report Section 1.4 – please note WP did not report coal flow or quality.
- Predicted turbine heat rate is original design, refer Munmorah drawing MM235960.
- For the 100% gas case, coal fired fouling is assumed to simulate boiler modification resulting in near design steam temperatures. Otherwise the gas consumption would be understated for the target load of 350 MW.

From the results in Table 3.2 it can be seen that:

- For the predicted performance main steam temperature is on design (566°C), however, hot reheat temperature is low at 522 – 529 °C compared to design at 538°C. Therefore fuel consumption is slightly understated.
- There is a slight reduction in boiler efficiency with increasing gas proportion. This is due to the greater hydrogen content of natural gas and increased losses due to moisture in flue gas.

2.2 Greenhouse Gas Emissions

The future greenhouse gas emissions from the proposed Munmorah upgrade have been predicted using the emission factors provided in *NGER (Measurement) Technical Guidelines 2009* produced by the Department of Climate Change. This study includes point source emissions (Scope 1), emissions from purchased electricity consumed on site (Scope 2), and Scope 3 emissions relating to the extraction and transportation of fuels.

The NGER Method 1 takes into account emissions of CO₂, CH₄ and N₂O.

2.2.1 Greenhouse gas emissions calculations

Direct greenhouse gas emissions (Scope 1)

The following tables outline the data and emission factors used in the calculation of the Scope 1 greenhouse gas emissions for the proposed Munmorah rehabilitation. Emission factors have been adopted NGER (Measurement) Technical Guidelines 2009. The Scope 1 emissions are provided in Table 3.5.

Table 3.3 Unit operational data for upgrade Scenario 5

Parameter	Value
Gross Power Output	350 MW
Capacity Factor	80%
Energy Generated per Year	2,452,800 MWh/year

Table 3.4: Greenhouse gas emission factors (NGER (Measurement) Technical Guidelines 2009)

Fuel Type	Greenhouse Gas	Greenhouse Gas Emission Factor (kgCO ₂ -e/GJ)
Black Coal (Gross SE = 27 MJ/kg)	CO ₂	88.2
	CH ₄	0.03
	N ₂ O	0.2
Natural Gas (Gross SE = 0.0393 GJ/m ³)	CO ₂	51.2
	CH ₄	0.1
	N ₂ O	0.03

Indirect greenhouse gas emissions (Scope 2)

The Scope 2 greenhouse gas emissions from the consumption of purchased electricity on site have been estimated using the 0.89 kgCO₂/kWh emission factor as stated in the NGER (Measurement) Technical Guidelines 2009. The amount of electricity purchased is estimated to be 2% of the total generated electricity, based on auxiliary load data provided by Delta Electricity. This 2% is in addition to the 5% auxiliary load taken from the total electricity generated.

The Scope 2 emissions for the Munmorah rehabilitation options are provided in Table 3.5.

Greenhouse Intensity

Table 3.5 shows the predicted greenhouse performance of the rehabilitated Munmorah Units compared to recent performance data. The recent

performance data using 100% coal (based on 290 MW per Unit operation on 13/12/2006) assumes a capacity factor of 80% for the entire year. The greenhouse intensity factors provided in Table 3.5 are instantaneous values at MCR.

Table 3.5 Estimated greenhouse gas emissions from rehabilitated units (2 Units)

Parameter	100% Coal 13/12/06	100% Coal	25% Gas	50% Gas	75% Gas
Unit Efficiency (HHV) (sent out)	32.9%	37.5%	37.4%	37.3%	37.0%
Scope 1 Greenhouse Gas Emissions (MtCO ₂ -e/year) (at 80% c.f)	3.74	3.96	3.55	3.15	2.75
Scope 2 Greenhouse Gas Emissions (MtCO ₂ -e/year) (at 80% c.f)	0.07	0.09	0.09	0.09	0.09
Total Greenhouse Gas Emissions (MtCO ₂ -e/year) (at 80% c.f)	3.81	4.04	3.63	3.23	2.84
Greenhouse Intensity Factor (kg CO₂-e/MWh_{SO})	988	868	780	694	608

2.2.2 NSW pool coefficient

The NSW pool coefficient is an indicator of the average greenhouse gas emissions produced from the generation of electricity sourced from the NSW electricity grid. The NSW pool coefficient represents the greenhouse gas emissions from Category B Generators (which includes Delta Electricity plants) as defined in Schedule B of the Greenhouse Gas Benchmark Rule (Generation) No. 2. The pool coefficient is measured in kilograms of carbon dioxide equivalent per megawatt hour of electricity sourced from the grid (kg CO₂-e/MWh_{SO}).

The NSW pool coefficient is calculated according to Clause 9.1 of the Greenhouse Gas Benchmark Rule (Compliance) No. 1. The NSW Independent Pricing and Regulatory Tribunal (IPART) is responsible for the annual calculation and publishing of the pool coefficient. The NSW pool coefficient can be used to compare the emission intensity of the coal and gas firing options against the existing average emission intensity in the NSW electricity grid.

The NSW pool coefficient for 2009 is **967 kg CO₂-e/MWh_{SO}** as published by IPART.

Comparison of Munmorah emission intensity to NSW pool coefficient

A comparison of the greenhouse intensity factors (provided in Table 3.5 above) and the NSW pool coefficient shows that all options for the Munmorah upgrade works would result in less greenhouse emissions than the average emissions from the NSW electricity grid.

The 100% coal firing option results in a greenhouse intensity factor of 868 kg CO₂-e/MWh_{SO}, which is below the 2009 NSW pool coefficient. With 25% gas firing, the greenhouse intensity factor is reduced to 780 kg CO₂-e/MWh_{SO}. The greenhouse intensity factor is reduced to 608 kg CO₂-e/MWh_{SO} with 75% gas firing.

The upgrade works under Scenario 5 will ultimately result in a reduction in the greenhouse intensity factor of the Munmorah Units compared to current operation. Calculations made from operational data using 100% coal from 13 December 2006 result in a greenhouse intensity factor of 988 kg CO₂-e/MWh_{SO}. All Scenario 5 upgrade options have a greenhouse intensity factor below these levels.

Figure 3.1 compares the predicted emissions intensity for the 5 scenarios with the 2009 pool co-efficient.

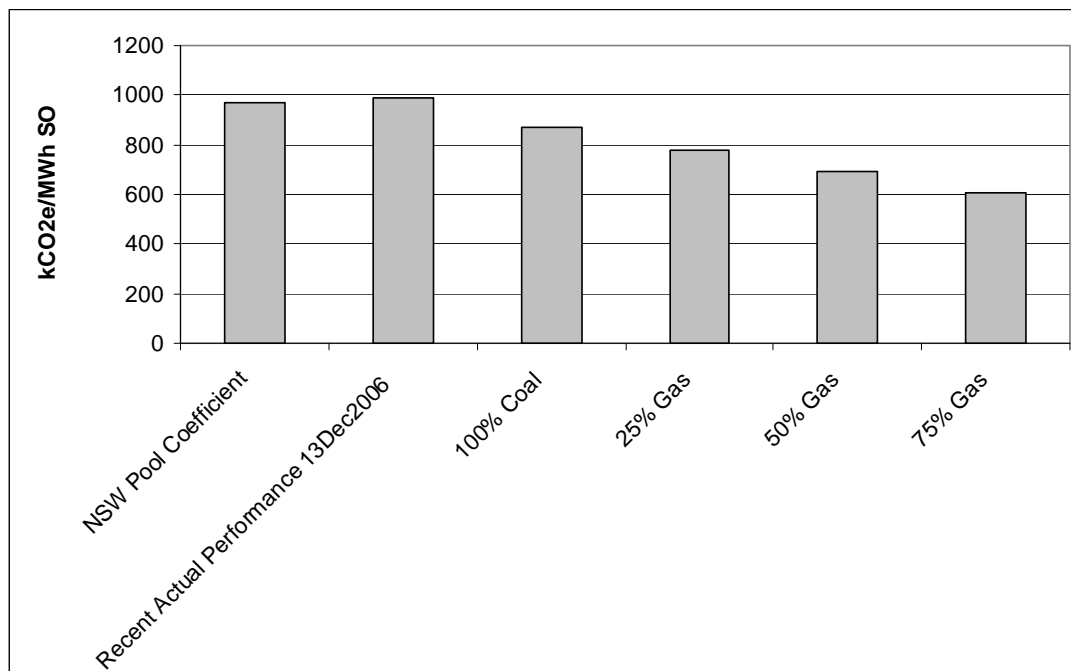


Figure 3.1 Predicted emissions intensity for the Munmorah rehabilitation scenarios compared with the 2009 pool co-efficient and recent 100% coal data

2.2.3 Contribution to national greenhouse gas emissions

The annual greenhouse emissions from the proposed Munmorah upgrade have been compared to the total Australian emission projections according to “Tracking to the Kyoto Target (2007)” released by the Australian Government Department of Climate Change. The report provides projected data for the years 1990, 2010 and 2020. This data has been linearly interpolated and projected to provide annual national emission data over the operating life of the proposed upgrade.

The report “Tracking to the Kyoto Target (2007)” projects emissions under two separate assumptions: “business as usual” in which no measures are taken to reduce greenhouse gas emissions, and a case in which measures are taken to reduce emissions. The “measures taken” projections have been used in this study to provide a conservative estimate of the percentage contribution to total national greenhouse gas emissions (Table 3.6). It has been assumed that the 20 year operational life of the upgraded plant begins in 2010.

If total national greenhouse gas emissions increase as expected, the percentage contribution of the Munmorah Units to total national emissions will decrease as long as the emissions from the Munmorah units remain steady.

Table 3.6 Contribution of Munmorah upgrade to total Australian greenhouse gas emissions (2 Units)

		100% Coal	25% Gas	50% Gas	75% Gas
Munmorah contribution to total Australian emissions	2010	0.68%	0.61%	0.54%	0.47%
	2030	0.55%	0.50%	0.44%	0.39%

2.3 NOx Emissions

All fossil fuels produce NO_x during the combustion process. Nitrogen oxide production is a function of the boiler and burner design, operating conditions and fuel properties. As part of the plant rehabilitation, low NO_x coal burners are proposed. As stated by SKM, the NO_x emissions with the new burners will be less than 500mg/Nm³. The use of gas will require new burners, which may also be specified as ‘low NO_x’, with a limit on emissions consistent with the new coal burners.

The use of gas will therefore not impact NO_x emissions compared to the 100% coal case.

2.4 SOx Emissions

The stack SOx emissions have been predicted based on the assumption that all sulphur in the fired coal is converted to sulphur dioxide (SO₂). It is also assumed that natural gas does not contain any sulphur. The SO₂ emissions have been calculated using Aurecon's boiler efficiency model, which has been verified and refined over a number of years.

The key inputs to the model include the fuel composition on an "as received" basis and the oxygen (O₂) levels in flue gas. The coal properties are the same as used in the PROATES modelling (Table 2.2). The SO₂ concentrations have been calculated using the reference conditions as outlined in the "Protection of the Environment Operations (Clean Air) Regulation 2002". Schedule 5 of this regulation states reference O₂ levels of 7% are to be used for SOx emissions for coal boilers.

The SO₂ concentration was calculated for the 100% coal case, and subsequently scaled for each gas option based on the percentage of coal fuel used. The results of the SO₂ emission concentration calculations for wet flue gas are summarised in Table 3.7

2.5 Particulate Emissions

Aurecon has concluded that the particulate emissions resulting from the proposed Munmorah upgrades should remain predominantly unchanged however this is largely dependant on flyash conditions.

The volumetric flow of the flue gas will be largely unchanged for all options, and the dust burden in the flue gas will vary with the amount of natural gas firing. The more gas firing that takes place, the lower the inlet dust burden of the fabric filter plant. Reduced inlet dust burden levels may assist in lowering fabric filter dPs and lengthening fabric filter bag cleaning cycles.

The precise impact of the gas firing on particulate emissions is unclear, as the combustion process may result in varying ash particle size distributions. If the combustion process results in a larger amount of finer ash, then the particulate emissions may increase relative to the amount of coal burnt. However the

reverse case is also true, in that a smaller amount of finer ash will improve the particulate emissions.

2.6 Stack Exit Conditions

The stack exit conditions have been estimated to allow for later plume dispersion modelling. They are based on data obtained from PROATES modelling and a report delivered by Howden ("Munmorah Unit 3-4: Draught and Fabric Filter Dust Collection Plant Study", 11 May 2009). The stack gas exit temperature and velocity has been calculated for the 100% coal case only, with both Units operating at 350 MW.

The stack exit temperature has been determined through a comparison of air heater gas inlet temperatures from the Howden's report and the PROATES modelling, with the existing air heater gas outlet temperature taken from the Howden's Heater Performance Assessment (October 2007) [Appendix H of the above Howden report]. It has been assumed that there is no temperature change across the fabric filter plant or the ID fan. The estimated exhaust stack exit temperature for the 100% coal option under the Scenario 5 upgrade proposal is given in Table 3.7 below.

The stack exit velocity has also been predicted from Howden's data and PROATES results. The volumetric flow rate of the flue gas is highly reliant on the gas density, and therefore gas temperature. The density of the gas flow has been calculated at specific locations between the air heater inlet and the stack exit based on temperature changes between these sections.

The volumetric flow rate at each location in the gas stream is calculated from the flue gas mass flow rate as provided by the PROATES modelling and the assumed 10% air leakage through the air heaters. It has also been assumed that there is no attemperating air required before the fabric filter plant.

The flue gas exit velocity is calculated using the final volumetric flow rate and the exhaust stack exit dimensions. The exhaust stack exit diameter is 7.9 m (data taken from the Colongra Gas Turbine EA).

The predicted flue gas stack exit velocity for the proposed Munmorah upgrade is summarised in Table 3.8.



Table 3.7 Exhaust stack exit temperatures

Location	Howden Temperature Data	Estimated Temperatures
Ambient	20°C	20°C
Air heater gas inlet	320°C	327°C ¹
Stack outlet	144°C	137°C

1. PROATES modelling result

Table 3.8 Exhaust stack exit velocity

Location	Parameter	Value
Stack outlet conditions for 2 Units	Volumetric flow rate	465 m ³ /s
	Stack exit velocity	19.0 m/s

1. PROATES modelling result

3. Ash Disposal Requirements

The modelling results described above were used to compute the ash disposal requirements for the various gas / coal scenarios. Table 4.1 summarises these results. All cases assume the 24% ash 'rehabilitation' design coal.

Table 4.1 Calculated ash production rates

	Original Performance	Recent Performance	Predicted Performance					Approx 80% LOAD
			0%	25%	50%	75%	100%	
Gas input energy	0%	0%	0%	25%	50%	75%	100%	0%
Total ash (kg/s)	10	9	10	7	5	3	0	8
Total ash (kt/yr/Unit)	324	298	306	233	157	79	0	259
Total ash (kt/yr/Station)	647	595	613	465	315	159	0	517
Fly ash (kt/yr/Station)	550	506	521	396	267	135	0	440
Bottom ash (kt/yr/Station)	97	89	92	70	47	24	0	78

4. Summary

The key quantitative results of the technical investigations described in this report are summarised in Table 4.1.

Table 4.1 Summary of results

Parameter	Units	Predicted Performance at 350MW (gen)				
Gas input energy	%	0	25	50	75	100
Coal rate	t/GWh-gen	416	316	214	108	0
Unit efficiency – s.o	%	37.5	37.4	37.3	37.0	36.8
Total greenhouse gas emissions (for 2 units @ 80% c.f)	mtCO ₂ -e/yr	3.96	3.55	3.15	2.75	2.34
Greenhouse Intensity	kg CO ₂ -e/MWh	849	761	675	590	502
NOx emissions	mg/Nm ³	<500	<500	<500	<500	<500
SO ₂ emissions	ppm v/v	341	256	171	85	0
Total ash production	Kt/yr	613	465	315	159	0



**Technical Investigations
Carbon Capture**

Appendix

D



**Technical Investigation
Carbon Capture and Storage
Applicability to Munmorah
Power Station**


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Document prepared by:

Aurecon Australia Pty Ltd
ABN 54 005 139 873
116 Military Road
Neutral Bay
New South Wales 2089 Australia

T: +61 2 9465 5599
F: +61 2 9465 5598
E: sydney@ap.aurecongroup.com
W: aurecongroup.com

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1. Introduction

In this study Aurecon investigated the requirements necessary to make the upgraded Munmorah units 3 & 4 “Carbon Capture Ready”.

The objective of the study was to assist Delta Electricity in confirming that in the near future the plant will be capable of being retrofitted with carbon capture and storage technology. The methodology followed to allow the plant to be transformed from capture ready to carbon capture operation should reduce the costs associated with retrofitting carbon dioxide (CO₂) capture in the future.

1.1 Objectives and Scope

Coal based power generation is under increasing pressure due to the enhanced greenhouse effect and the consequent need to minimise carbon dioxide emissions. Carbon dioxide capture and storage (CCS) is considered to be a key climate change mitigation option for the future and as a result there is significant research and development effort focusing on the development of CCS technologies. To avoid the undesirable outcome that all new coal fired plants continue to operate at the same CO₂ emissions intensity value for their lifetimes, there is a current trend to build ‘capture ready’ plant. Therefore as legislation changes, CCS technology improves or there is a financial benefit in operating CCS, the carbon capture facilities may be retrofitted.

The prime objective of this study is to ensure that the plant will not be precluded from being retrofitted with CCS at some point in the future. The study addresses:

- Steam supply options for solvent regeneration.
- Boiler and / or turbine modification for steam take-off.
- Flue gas quality requirements for CO₂ scrubber inlet.
- Additional electrical load of scrubbing plant.
- Cooling water requirements of scrubbing plant.
- Site area and layout requirements of capture facilities.
- Interface issues.

2. Definition of a Carbon Capture Ready Power Plant

Although many new coal fired plants are being built as 'carbon capture ready', at present there is no universal definition of what carbon capture ready means. The most appropriate and widely used definitions were found by reviewing the literature; and are listed below:

Bohm, MIT (2006): *"A plant can be considered 'capture ready' if at some point in the future it can be retrofitted for carbon capture and sequestration and still be economical to operate"*

International Energy Agency (2007):

- *"It is one which can include CO₂ capture when necessary regulatory or economic drivers are in place"*
- *"Developers of capture ready plant 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 CO₂ capture retrofit and potential pre-investments*
 - *Inclusion of sufficient space and access for additional facilities that may be required*
 - *Identification of reasonable route(s) to storage of CO₂.*"

For this study the IEA definition has been assumed.

3. Review of Carbon Capture Technologies

Carbon capture technologies already exist and have been used for decades in the oil and gas and petrochemical industries. However there is a need for these technologies to be implemented in the power generation industry, as carbon capture technologies need to be scaled for full size for coal/gas power plants.

Carbon dioxide capture and storage is a process consisting of:

- i) Capture or separation of CO₂ from industrial and energy related sources
- ii) Transport of CO₂ to a storage location
- iii) Injection into storage site for long term isolation from the atmosphere

When coal is burned for power generation, an exhaust (flue) gas stream comprising predominantly nitrogen, carbon dioxide, water vapour and oxygen is produced. Typically, the CO₂ concentration of the flue gas is approximately between 12%-15% (v/v). For a large coal fired power plant, the flue gas production rate is very high.

The storage of CO₂ from sources such as power plants requires that the CO₂ is first isolated from other gases. This is because it would be impractical to store flue gas with all its constituents due to costs associated with transportation and compression as well as storage space considerations.

There are three generic types of CO₂ capture systems demonstrated or proposed for fossil fuel fired power plants:

- **Post-combustion:** This system involves the capture of CO₂ from all or part of the flue gas stream. A number of technology options are available, a few of which are commercially used for the separation of CO₂ from natural gas.

- **Oxy-fuel combustion:** This technology entails burning the fuel in high purity oxygen. This results in high CO₂ concentrations in the flue gas stream and therefore easier separation.
- **Pre-combustion:** This option is only suitable for the IGCC generation technology. It involves the separation of hydrogen and carbon dioxide prior to the combustion of the syngas. The technology is widely applied in the manufacture of fertilisers and in hydrogen production.

3.1 Status of Carbon Dioxide Capture Technologies

A number of the proposed CO₂ capture technologies are still at the laboratory or pilot stage and therefore would not be suitable for use with a base load power station. Table 1 lists the carbon dioxide capture technologies that have been identified and indicates the state of development of the technology.

Critical factors that will impact the suitability of CO₂ capture technology to be used with base load power generation include:

- maturity and timeframe for availability
- construction cost
- energy consumption and impact of system on power plant output and efficiency
- operating and maintenance costs
- CO₂ capture efficiency
- requirement for gas pre-treatment

It is considered that post-combustion capture would be the most likely to be considered for a power plant retrofit in the foreseeable future, due to its proven demonstrated usage in other industries.

Table 1: Commercial Status of Potential CO₂ Capture Technologies

Capture Type	Technology	Status of Development
Post Combustion	chemical absorption - amine	economically feasible under specific conditions
	chemical absorption -chilled ammonia	demonstration phase
	membrane separation	economically feasible under specific conditions
	solid sorbent	research phase
	cryogenic	economically feasible under specific conditions
Oxy- Fuel Combustion		demonstration phase
Pre- Combustion	physical absorption -Selexol	economically feasible under specific conditions
	physical absorption -Rectisol	economically feasible under specific conditions

3.2 Options for Post Combustion Carbon Dioxide Capture

Post-combustion capture systems have been the subject of significant development effort as they are suitable for retrofit to existing power plants. There are several technologies that are either presently used or have been proposed for the removal of CO₂ from flue gas streams. They include:

3.2.1 Chemical absorption processes

These are based on chemical solvents and are currently the most used option for post-combustion CO₂ capture. Absorption processes in post-combustion capture make use of the reversible nature of the chemical reaction of an aqueous based solvent, usually an amine or ammonia. Typically, post-combustion capture involves two stages: First, flue gas is passed through an absorber, where a solvent removes most of the CO₂ through a chemical reaction. Then this CO₂ - rich solvent goes to a stripper, where it is heated to release the CO₂ and produce a regenerated solvent, which is returned to the absorber. Figure 1 illustrates the process schematically.

Amine Solvent Process

The most commonly used chemical absorption process for CO₂ capture uses amines such as MEA as a solvent. The process is widely used in the beverage and petrochemicals industries.

CO₂ in the gas phase dissolves into a solution of water and amine compounds. The amines react with CO₂ in solution to form protonated amine (AH⁺),

bicarbonate (HCO₃⁻), and carbamate (ACO₂⁻). As these reactions occur, more CO₂ is driven from the gas phase into the solution due to the lower chemical potential of the liquid phase compounds at this temperature. When the solution has reached the intended CO₂ loading, it is removed from contact with the gas stream and heated to reverse the chemical reaction and release high-purity CO₂. The CO₂-lean amine solvent is then recycled to contact additional gas. The resulting pure CO₂ stream is then recovered. Compression, and the associated energy costs, would be required for geologic storage. Research on improved solvents with reduced regeneration energy is underway.

Commercial amine absorption systems are available from a number of vendors.

Amine scrubbing systems are capable of the removal of between 80 and 95% CO₂ in a flue gas stream.

It is essential that acid gases such as NO_x and SO_x be removed from the flue gas prior to passing through the absorber tower. NO_x and SO_x reacts with the amine and will result in a reduction in solvent performance and higher chemical consumption.

Chilled Ammonia Process

This process is also a chemical absorption process but using ammonia rather than an amine as the solvent. Ammonia reacts with CO₂ and water to form ammonium carbonate or bicarbonate. There is significant interest in this process at present due to a number of potential advantages over the amine process. Benefits include a lower energy requirement for regeneration and reduced sensitivity of the solvent to acid gases such as SO_x and NO_x.

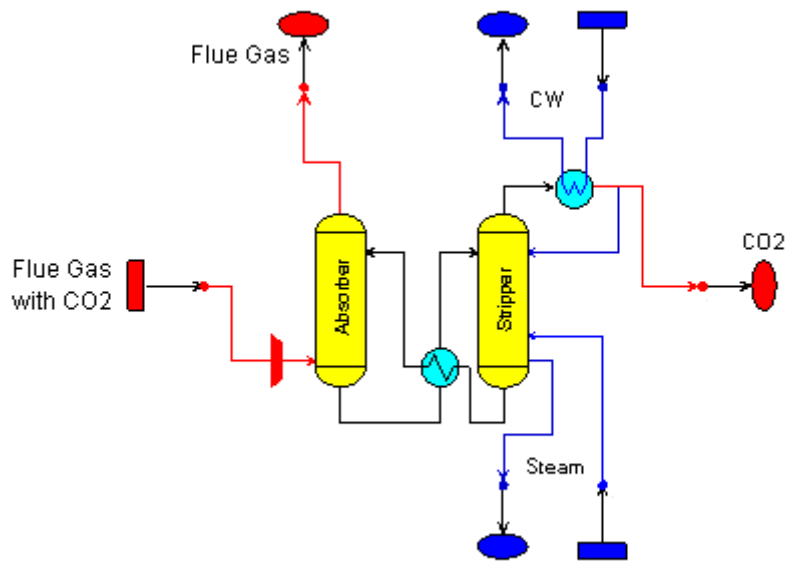


Figure 1: Schematic of Chemical Absorption CO₂ Capture Process

3.2.2 Physical Absorption

Physical absorption processes involve the use of absorbents that allow CO₂ to permeate a solid or liquid under given conditions, and to desorb under other controlled conditions. Physical solvent scrubbing of CO₂ is established, with Selexol, a liquid glycol based solvent having been used by the natural gas industry for many years. A characteristic of the Selexol process is the low pressure release of CO₂, resulting in additional compression following release.

3.2.3 Membrane Separation

Membrane separation systems comprise thin barriers that allow the selective permeation of certain gases, allowing a particular gas to pass through at a higher rate than others. This type of gas separation has been widely used for hydrogen recovery in ammonia synthesis, removal of CO₂ from natural gas and nitrogen separation from air (Figure 2).

3.2.4 Solid Sorbents

Under some conditions, CO₂ can undergo a reversible chemical reaction with a dry absorbent material. The chemical reaction can later be reversed by changing the conditions, resulting in the release of pure CO₂.

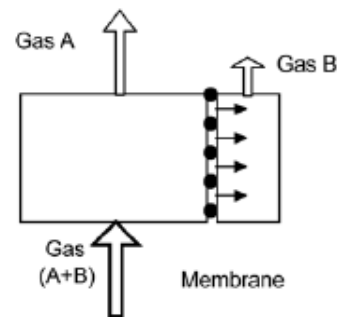


Figure 2: Membrane Separation Process

3.2.5 Cryogenic separation

Cryogenic separation or low temperature distillation allows separation of CO₂ from flue gas mixtures due to the differing boiling points of these gases. A characteristic of this method of separation is the high refrigeration energy requirement.

4. Munmorah Power Station Modifications for Future Carbon Capture

4.1 Assumed Capture Technology

A difficulty in designing a plant to be 'capture ready' is uncertainty in the availability of a specific capture technology, particularly in view of the amount of work that is presently being undertaken on the development of capture technologies. For Munmorah Power Station Units 3 and 4, a conservative approach has been adopted which assumes that the amine post-combustion capture process will be the preferred technology. Should an alternative such as chilled ammonia be available, there will be a lesser impact on the existing plant. These options will be reviewed in detail at the power station detailed design stage.

It has been assumed that the carbon dioxide capture plant will be sized to handle one million tonnes CO₂ per year, since that is the module size **currently under development by vendors**. However, it is assumed a capture ready plant would be capable of accommodating capture modules over time totalling 100% flue gas flow. The indicative inlet conditions to the scrubber train (per boiler) are provided in Table 2 below.

Figure 3 below presents a schematic diagram of how the capture plant will fit into the overall coal fired plant process.

Table 2: BMCR Conditions at CO₂ scrubber inlet

Inlet flue gas mass flow	kg/s	391
Inlet gas composition		
CO ₂	% v/v	12
H ₂ O	% v/v	14
O ₂	% v/v	3
N ₂	% v/v	70
Ar	% v/v	1
SO ₂	% v/v	0.0004
Inlet CO ₂ mass flow	kg/s	71.77

A typical process flow diagram is included as Figure 3. The cooled flue gas is brought into contact with the solvent in the absorber at temperatures of 40 to 60C. The carbon dioxide in the flue gas is reduced from 12% (v/v) to less than 2% (v/v) via reaction with the MEA solution. This is followed by a water wash to remove any solvent carryover. The solvent containing the CO₂ is then pumped to the stripper vessel, where the MEA is heated to release pure carbon dioxide. The stripper needs to operate at around 100 - 140C to allow the CO₂ to be released from the MEA solution. For the quantity of flue gas to be treated at Munmorah, two absorber and stripper trains are expected to be required.

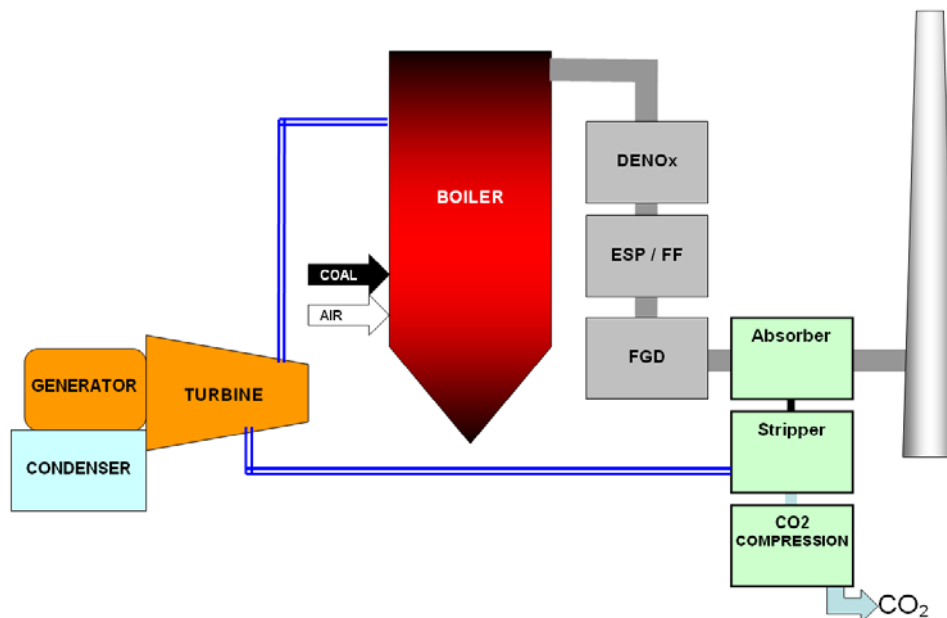



Figure 3: Schematic of carbon dioxide capture concept



As can be seen in Figure 1, there are fans, pumps, heat exchangers and heat input necessary for the operation of the plant. The scrubbing system is followed by CO₂ compression to around 10MPa allowing it to be pumped as a liquid through a pipeline to the storage location.

4.2 CO₂ Capture Plant Integration

Careful provision for future post combustion CO₂ collection unit needs to be made to ensure optimum integration and economic retrofit as there are large impacts on power station performance and costs as described below. Although CO₂ capture technology may be retrofitted to coal fired plants, a degree of integration with power station equipment is required. Capture technologies are developing rapidly and there is a possibility that configuring a power plant design for equipment available now may lock in obsolescence as technologies available in the medium term may be significantly different. The following section describes interactions which could be considered for existing CCS technologies, however detailed study of capture retrofit options would be deferred and undertaken as late in the power station final design stage as possible, to manage this risk.

The main impacts and interactions with power station equipment occur in the following areas:

1. Flue gas ducts
2. Flue gas cleaning
3. Steam for solvent regeneration
4. Electrical auxiliary power consumption
5. Auxiliary cooling system
6. Other technical requirements for capture retrofit
7. Adequate space
8. Plant layout to optimise the integration of additional process equipment that would be required
9. Route for transport of CO₂ to storage.

These are each discussed in further detail below.

4.2.1 Flue gas ducts

Space is necessary for the installation of new duct work to enable interconnection of the boiler flue gas system with the amine scrubbing plant. Provision in the ID fan discharge duct to allow for a take-off to the CO₂ scrubber will be necessary. The take-off must be

large enough to allow 100% of the flue gas to be routed to the CO₂ scrubbing facility.

4.2.2 Flue gas cleaning

Amine Scrubbers require the flue gas to be low in acid gas concentrations, as the presence of the acid gases leads to solvent degradation. Typically, the SO₂ concentration in the flue gas is required to be <10ppmv (approx 30mg/Nm³). NO_x levels are also required to be low, with NO₂ concentration limits of <20ppm being necessary.

To achieve less than 20ppm NO_x and less than 10ppmv SO₂ is via post-combustion DeNO_x such as SCR and flue gas desulphurisation (FGD) respectively. Allowance needs to be made in the site layout to allow for the retrofit of SCR and FGD at the time of CCS retrofit. Space for future booster fan or allowance for upgrade of existing fan to overcome flue gas pressure loss through the SCR should also be considered.

4.2.3 Steam for Solvent Regeneration

One of the most significant impacts of the retrofit of carbon capture technology is the requirement for heat energy to regenerate the amine solvent. For a standard amine solvent, the regeneration energy requirement is approximately between 3.2 to 4MJ/kg

CO₂ depending on the process and level of plant heat integration.

Typically the stripper operates at 120°C and the steam supply is at around 350kPa and 140°C. There are a number of options for the future provision of steam to deliver this energy requirement Table 3).

Table 3: Steam for Solvent Regeneration

I - Removal of 1 LP turbine	The feedwater heating train would need to be optimised to minimise the impact on cycle efficiency. To allow for this option, installation of a valve and tee-piece on the IP/LP crossover would allow for future tapping of steam. This option need to be integrated with SKM proposed work as suggested in the in the scope list (Section 3) of the SKM report (July 2009)
II – Replace LP with steam driven CO₂ compressor	As the steam conditions of the IP exhaust are in excess of that required for solvent regeneration, it may be possible to extract energy from this steam via a backpressure turbine running the CO ₂ compressor. Space would need to be allocated near to the IP turbine for the steam driven CO ₂ compressor. Turbine exhaust would then be piped to the stripper for solvent regeneration. This option need to be integrated with SKM proposed work as suggested in the in the scope list (Section 3) of the SKM report (July 2009).
III – Separate boiler for solvent regeneration heat	A lower initial cost option is to allow for the future installation of an auxiliary boiler for solvent regeneration steam demand. This would require space allocation near the stripper columns and corridors for fuel feed and flue gas exhaust.

Based on the above, the optimal approach that would not preclude the future retrofit of CO₂ capture, and have minimal impact on post-retrofit plant output is option III. A further advantage of option III is that as better solvents having lower regeneration energy requirement are developed, the size of the required auxiliary boiler will decrease. Thus the plant can be optimised at the time of retrofit. The separate boiler option would also allow for alternative fuels such as gas or waste material to be considered for this boiler.

4.2.4 Electrical auxiliaries

The capture plant contains a number of pumps and significantly, a gas compressor for conversion of the gaseous CO₂ to liquid. These will have additional electrical load. These auxiliary electrical loads are based on the current state of amine CO₂ capture technology, which is very energy intensive. The auxiliary electrical loads (per unit) will require an additional 35MW for the CO₂ capture and compression. These auxiliary electrical supplies most likely will have to be sourced either from the PIB or the 330kV independent of the existing unit and station supplies. This option need to be integrated with SKM proposed work as suggested in the SKM report “Munmorah Units 3 and 4 Rehabilitation Studies” dated 8/7/2009, item # 54 and 55 in the scope list (Section 3). Note the opportunity to use the existing

330kV from Munmorah Units 1 & 2 bays in the switchyard.

SKM recommended (July 2009) the replacement of 2A and 2B station transformers, hence they should be considered for uprating to accommodate the extra CCS requirements.

4.2.5 Auxiliary cooling system

There is a large cooling demand to limit process temperatures. It is estimated that up to 16% of the excess heat can be recovered within the turbine cycle or for combustion air pre-heating. Cooling is required for the scrubber unit, solvent cooler, stripper regeneration condenser and CO₂ compressor inter cooling.

4.2.6 Other technical requirements for capture retrofit

Flue gas cooling before the scrubber might affect the stack plume height due to a decrease in the buoyancy. Hence, a gas - gas heat exchanger might be required.

An additional water treatment plant might be required to supply enough water for the aqueous effluent.

4.2.7 Adequate Space and Plant Layout

Adequate space to allow for the major equipment (See Table 4 and Table 5) of carbon capture, transport and storage plant should be allowed for in the site layout.

allocated space is not sufficient for a CCS plant to be built in the optimum location (close to boiler and turbine house). However there are few options proposed such as demolishing unit 1 and unit 2 or extending the proposed lot to the north east of the boiler and turbine house.

From the proposed lot drawings by Monteath & Poweys with Ref No:09/085A; it appears that the

Table 4: Major Equipment of Carbon Capture Plant

Item/Equipment	Description/Purpose
Plant Layout	Space allowance to allow for optimum arrangement of future interfaces
Plant infrastructure	Including roads, office space, stores, cable trenches, fire protection system
Flue Gas Ducts	Flue gas ducting
FGD and SCR	Flue gas cleaning plant to reduce solvent degeneration
Future auxiliary steam generator	Space to be provided to allow for auxiliary boiler or use of exhaust from on-site gas turbine for steam generation
Electrical	Additional loads
Auxiliary Cooling System	
Blower (Fan)	To transfer and raise the pressure of the flue gases before the capture process
Gas Cooler	To cool the flue gases to a temperature suitable for the absorber (If wet FGD is not used)
Absorber	Solvent falling through the absorber tower reacts with CO ₂ to form an intermediate compound
Pumps	To transfer solvent, CO ₂ - rich solvent, condensate, lean solvent or rich solvent between different stages of the process
Stripper	CO ₂ - rich solvent is heated to release the CO ₂ and regenerate the solvent
Reboiler	To break-up the CO ₂ - rich solvent into CO ₂ /steam stream and lean solvent
Condenser	To cool a stream between different stages of the capture process
Pressure Vessels	To store solvent, CO ₂ and condensates
Multi-stage Intercooled Compressor	CO ₂ Compression
Additional C&I inputs & outputs	<ul style="list-style-type: none"> • Network to handle extra signals • Provision for control room extension
Pipelines	CO ₂ Transport



**Table 5: Land Area Allocation for Munmorah 3&4
Future Carbon Capture Plant**

Plant size for Munmorah 700MW	Plot Area
CO ₂ Capture and Compression Plant	2 x (100m x 100m) or 2 hectare
FGD plant/SCR (if necessary)	1 x (100m x 100m) or 1 hectare
Water treatment, waste water tank, limestone storage, gypsum dewatering, gypsum silo, stacking tank	1 x (50m x 100m) or 0.5 hectare
Contractors accommodation, car park and the lay-down area for the prefabricated part	9 hectare

5. Geological Storage

I&I NSW is conducting a NSW State Wide Assessment of Storage Capacity to assess the regions' basins and their potential suitability for CO₂ storage. This Project is critical for identifying geological storage sites for future use. The models developed from this work will be used, to determine the final location and operation of the integrated demonstration CCS plant.

Stage 1 of the Regional Stratigraphic Drilling Program commenced in January 2009 to locate and investigate potential permeable reservoirs, primarily sandstone beds, within the Sydney-Gunnedah Basin sequence that may be suitable for the geosequestration of CO₂. This stage of the drilling project includes drilling and analysis of four wells in the Sydney and Gunnedah Basins.

The first well was drilled at Munmorah power station and completed in June 2009. Drilling at a second well is underway near by at Vales Point Power Station, with data and recommendations from both wells expected to be available in December 2009. Depending on the results of Stage 1 work further wells may be drilled in the Sydney Basin.

Stage 2 is a broader state wide regional assessment of large scale storage potential focussing on the Darling, Clarence Moreton Basins.

The drilling program will provide information that will allow more accurate modelling and prediction of reservoir characteristics in the Sydney and Gunnedah Basins. The overall work program to gain a full picture of the NSW sequestration potential.