SINCLAIR KNIGHT MERZ
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Dual Gas Pty Ltd

Dual Gas Demonstration Project

EPA WORKS APPROVAL APPLICATION

- Final - Amended
- 1 September 2010

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Executive Summary

Dual Gas Pty Ltd (Dual Gas) proposes to develop a new power station to generate base load power whilst demonstrating new power generation technology at commercial scale at a site in Morwell, Victoria. Dual Gas is a special purpose company that has been established by HRL Limited (HRL) to develop the Dual Gas Demonstration Project.

The Dual Gas Demonstration Project (DGDP) will use HRL's Integrated Drying and Gasification Combined Cycle (IDGCC) technology. It involves the development of an approximate 600MW demonstration power station and associated infrastructure including an approximate 4 km 500kV transmission line to connect the demonstration power station to the existing Hazelwood Terminal Station.

The primary fuel used for power generation will be synthesis gas ('syngas') generated from brown coal, and natural gas is expected to be used as start-up fuel, as well as a supplementary fuel. The Integrated Drying and Gasification Combined Cycle (IDGCC) process integrates the drying of raw wet coal with coal gasification, syngas cleaning and gas turbine power generation technologies to produce electricity from low rank coals with significantly lower CO_2 emissions per MWh than current existing technologies. The main components of this process are:

- Two integrated drying and gasification (IDG) plants (where the coal is dried and gasified); and
- Two combined cycle (CC) power plants (where the power is generated).

It is the intention of Dual Gas to commence construction works of the combined cycle power plants and one of the two IDG plants in early 2011. This will enable the first part of the plant (IDG No. 1) to be operational in 2013. Subsequently, construction of IDG No. 2 will begin in early 2014 with full DGDP operation planned for 2015.

Pursuant to Section 19A of the *Environmental Protection Act 1970*, a Works Approval is required prior to the commencement of the construction works. This document supports the Dual Gas application for a Works Approval, providing information on the proposed development and an assessment of the potential environmental impacts of this development.

Details of the application have been consolidated into this document. This report is based on the Works Approval Guidelines (Publication 1307.2, July 2010, EPA Victoria) and addresses all environmental issues considered relevant to the application, namely:

- Information on the applicant (Section 1)
- Description of the proposal (Section 2)
  - Rationale and background of the demonstration project proposal (Section 2.1.1)

- Information on the subject site and surrounds (Section 2.1.2 and 2.1.3)
- Description of the proposed development (Section 2.1.4)
- Description of approvals required for the project (Section 3)
- Information on the environmental considerations and community engagement activities (Section 4)
- Description of the process involved and justification of environmental best practice (Section 5)
- Assessment of potential environmental impacts through the use of resources and emissions to the environment (Section 6 and 7)
- Description of proposed environmental management practices (Section 8)
- Further details of: carbon, water, waste, air, land and groundwater, noise and environmental management are provided in Sections A to I.
- Relevant assessment reports are also attached as Appendices to this document.

A comprehensive range of environmental assessments have been undertaken to understand and mitigate potential environmental effects associated with the construction and operation of the demonstration power station. These assessments include:

- Water Use Assessment (Appendix B)
- Air Quality Assessment, including dispersion modelling (Appendix C)
- Greenhouse Gas Assessment (Appendix D)
- Noise Assessment, including modelling (Appendix E)
- Class 3 Air Pollutants Assessment (Appendix F)
- Planning and Land Use Desktop Assessment, including land tenure analysis and analysis of Planning Scheme Zones and Overlays (SKM, 2009a)
- Terrestrial Flora and Fauna Desktop Assessment (SKM, 2009b)
- Freshwater Ecology Desktop Assessment (SKM, 2009c)
- Geomorphology, Waterway and Hydrology Desktop Assessment (SKM, 2009d)
- Hydrogeological Desktop Assessment (SKM, 2009e)
- Phase 1 Environmental Site Assessment (SKM, 2009f)
- Traffic and Transport Desktop Assessment (SKM, 2009g)
- Air Quality Desktop Assessment (SKM, 2009h)
- Desktop Social Impact Assessment (SKM, 2009i)
- Cultural Heritage Desktop Assessment (SKM, 2009j)

Based on the environmental assessments undertaken, it is determined that the operation of the DGDP will not significantly impact the environment and compliance is expected to be achieved for

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all relevant legal environmental requirements. This includes the potential night time noise exceedence, where compliance is expected to be achieved once additional sound data and/or identified noise mitigation measures are applied. Monitoring programs (see Section I2) will allow close analysis to ensure long term compliance. The key environmental investigations - Greenhouse Gas Emissions, Air Quality, Water Usage and Noise - undertaken as part of this Works Approval Application have assessed the potential environmental impacts in depth and a summary of the outcomes are provided below:

Greenhouse Gas Emissions

- HRL has determined that DGDP will have a theoretical maximum emission of 4.2 million tonnes of CO_2-e* in any year of its life span (nominally 30 years). This maximum annual emission amount is based on full output of the demonstration power plant, with the gas turbines fired 85% of the time on syngas and fired 10% of the time on natural gas. The actual level of emissions within any given year will depend upon the capacity factor of the demonstration power generation plant and the quantities of fuel used – influenced by a range of market factors including:
  - Price of electricity, influenced by electricity demand and supply factors;
  - Cost, quality and usage of natural gas;
  - Cost and quality of coal; and
  - Cost of carbon permits.
- Four scenarios were studied for DGDP covering a wide range of syngas and natural gas usage scenarios. Cases 1-3 are IDGCC success scenarios. Case 4 is an IDGCC non-success scenario. For the three success cases, the average greenhouse gas emissions is expected to range between 3.0 and 3.2 million tonnes of carbon dioxide equivalent (Mt CO_2-e) per annum. The Greenhouse Gas (GHG) emissions Intensity (GGI) of the DGDP is expected to lie within the range 0.73 to 0.78 tonne CO_2-e per MWh generated over the life of the project. The predicted GGIs:
  - Comply with the Victorian Government's Victorian Climate Change White Paper target intensity of 0.8 t CO_2-e per MWh for new power stations;
  - are 31% to 36% lower than the current best performing Latrobe Valley brown coal power station; and
  - are lower than any current black coal-fired power generation plant operating within the NEM, (GGIs ranging from approximately 0.80–1.00 tonne CO_2-e per MWh.

* Carbon dioxide equivalent (CO_2-e).

- Operation of the DGDP with the Commonwealth Government's proposed Carbon Pollution Reduction Scheme (CPRS) in place may displace other power generation technologies with higher GGIs resulting in an overall reduction in GHG emissions intensity associated with power generation in Victoria.

Air Quality

- The key air pollutants associated with operation of the DGDP with respect to highest risks posed to ambient air quality, are oxides of nitrogen (NO_x) and sulfur dioxide (SO_2). Emissions of other air pollutants were found to be negligible; e.g. particulate matter.
- SO_2 and NO_x emissions are significantly lower than those from existing Latrobe Valley brown coal-fired power stations due to a lower rate of coal usage. The (corrected) NO_x concentration in the stack is expected to be significantly lower than that for all existing brown coal fired power stations, resulting in significantly lower total NO_x emissions for an equivalent sized power station. The use of pre-combustion, ceramic filter technology results in almost complete removal of particulate matter when operating on syngas, and a substantial reduction in particulate emissions compared with conventional brown coal-fired power stations.
- To assess compliance with the State Environment Protection Policy - Air Quality Management (SEPP-AQM) Schedule A and Schedule E, a detailed air quality assessment utilising air dispersion modelling of point source emitters has been undertaken.
- The modelling shows that the 99.9th percentile 1-hour ground level concentrations of NO_2 and SO_2 are below the SEPP-AQM design criteria.
- Modelled concentrations at various discrete receptor locations, including the present-day Latrobe Valley Air Monitoring Network stations are also below the SEPP-AQM design criteria for the modelled parameters.
- Furthermore, an assessment of Class 3 indicators has also been undertaken which shows that the addition of the DGDP to the air shed should not significantly impact the ground level concentrations of Class 3 indicators in the Latrobe Valley and should not result in the relevant SEPP Design Criteria being exceeded.

Water

- Up to 2 GL/yr is expected to be required during operation of the proposed DGDP. Following discussions with the Victorian Government's Departments of Treasury and Finance (DTF) and Sustainability and Environment (DSE), Dual Gas has been provisionally provided a 2 GL/yr water allocation from Blue Rock Dam, with a reliable yield of 95% for their operations (in line with Gippsland Water's service level commitment).
- The DGDP is expected to use 75% less water per MWh than the best practice (in regards to water consumption) existing brown coal fired power station in the Latrobe Valley. Under CPRS, if the demonstration power station displaces some existing Latrobe Valley brown coal

fired power station generation, it is anticipated that there would be an overall decrease in fresh water consumed by the Latrobe Valley brown coal fired electricity generators.

Noise

- The proposed DGDP is located in an industrial environment with relatively low background noise levels. The distance to the closest sensitive receivers is approximately 1.3 km north of the proposed demonstration power station site.
- A detailed noise and vibration assessment has been undertaken to ascertain the significance of potential impacts and to ensure that the DGDP is designed and developed to comply with the most current version of the draft State Guidelines assessing acceptable noise levels from industrial premises “Noise From Industry in Regional Victoria” (Publication 1316, December 2009). The assessment utilises noise criteria measured in accordance with the State Environment Protection Policy No. N-1 “Control of Noise from Commerce Industry and Trade” criteria at the nearest sensitive receivers.
- Noise emission modelling based on preliminary sound data from the demonstration power station indicates potential non-compliance at night at the closest receiver. The model has been noted as conservative and the demonstration power station is expected to comply once additional sound data and/or identified noise mitigation measures are applied. Noise mitigation measures have been identified and are listed in Section 7.4 of this document.

In summary, the proposed DGDP aims to generate base load power while emitting less CO_2 per MWh and using less water per MWh than any other coal-fired power station in Australia. In addition, the project aims to demonstrate the IDGCC technology which, if widely rolled out, has the potential to result in significantly reduced CO_2 emissions and water usage from base load brown coal-fuelled power generation in Victoria, Australia and overseas.

Abbreviations

ACC	Air Cooled Condenser
CCS	Carbon Capture and Storage
DD	Design and Development
DGDP	Dual Gas Demonstration Project
DGDPS	Dual Gas Demonstration Power Station
DPCD	Department of Planning and Community Development
DSE	Department of Sustainability and Environment
EBAC	Energy Brix Australia Corporation
EES	Environment Effects Statement
EPA	Environment Protection Authority Victoria
EPC	Engineering, Procurement and Construction
ESO1	Environmental Significance Overlay- Schedule 1
ETIS	Energy Technology Innovation Scheme
FZ	Farming Zone
GGI	Greenhouse Gas Intensity (units usually t CO_2-e/MWh)
GHG	Greenhouse Gas
GT	Gas Turbine
HRSG	Heat Recovery Steam Generator
IDGCC	Integrated Drying and Gasification Combined Cycle
IN1Z	Industrial 1 Zone
LETDF	Low Emissions Technology Demonstration Fund
NEM	National Electricity Market
ST	Steam Turbine
STG	Steam Turbine and Generator
SUZ1	Special Use Zone – Schedule 1
SUZ5	Special Use Zone – Schedule 5
RZ1	Residential Zone 1

1. APPLICANT

1.1. Company details

Company name: Dual Gas Pty Ltd is a special purpose company that has been formed to build, own and operate the Dual Gas Demonstration Power Station. Dual Gas' Certificate of Incorporation is included in Appendix A.

ACN: 117 102 244

Registered address: Unit 9, Level 1, 677 Springvale Road, Mulgrave 3170

1.2. Contact details

Name: Paul Welfare
Position: General Manager (Dual Gas Pty Ltd)
Phone: 03 9565 9896
E-mail: pwelfare@hrl.com.au

Name: Shelley Ada
Position: Project Manager (Sinclair Knight Merz Pty Ltd)
Phone: 03 9248 3417
E-mail: SAda@skm.com.au

1.3. Premises details

Premises Address: Commercial Rd, Morwell, VIC 3840
Municipality: Morwell

2. PROPOSAL

2.1. Project Description

The Dual Gas Demonstration Project (DGDP) comprises the development of a demonstration power station using Integrated Drying and Gasification Combined Cycle (IDGCC) technology, which will generate approximately 600MW of power for sale in the National Electricity Market (NEM). The primary fuel used for power generation will be synthesis gas ('syngas') generated from brown coal, and natural gas is expected to be used as start-up fuel, as well as a supplementary fuel.

Approximately 4 km of 500kV transmission line, from the proposed demonstration power station site to the existing Hazelwood Terminal Station, will also be built as part of the Project, but this project component is outside of the scope of this Works Approval application.

Dual Gas is a special purpose company that has been established by HRL Limited (HRL) to develop the DGDP.

2.1.1. Project Background and Rationale

2.1.1.1. The need for additional power generation in Victoria

According to the Electricity Statement of Opportunities (ESOO) (AEMA, 2009) published annually every year by the Australian Energy Market Operator (AEMO), (formerly the National Electricity Market Management Company (NEMMCO)), the gap between supply and demand for power within Victoria has been steadily moving from excess supply to a deficit.

In the ESOO published in August 2009, AEMO indicated that the point, known as the Low Reserve Condition (LRC), when additional capacity may be needed to maintain the established level of electricity supply reliability is the summer of 2013/14 in Victoria and South Australia combined. This assumes that no capacity in addition to that already committed is made available to the market and that no capacity is retired. Currently there is considerable uncertainty surrounding the electricity supply industry, with potential retirements of older less efficient plants due to the Commonwealth Government's proposed Carbon Pollution Reduction Scheme (CPRS).

[Note - In the 2008 ESOO, NEMMCO indicated that the LRC point was the summer of 2008/09. The 2009 ESOO has deferred this to the summer of 2013/14 due to the impact of the global financial crisis and forecast continued weakness in the Victorian and national economies, together with committed new generation capacity. There were electricity generation shortfalls in the summer of 2008/09 which led to interruptions to electricity supplies for Victorian customers.]

The proposed demonstration power station of the DGDP is planned to be commissioned to supply full generation capacity (approximately 600MW) to the grid by 2013, and thus is expected to assist in meeting Victoria's projected growing electricity demand.

2.1.1.2. Climate change and requirement to reduce carbon intensity and water usage

Commonwealth and State Policy Direction

The Australian Government believes that acting on climate change is essential (Australian Government, 2008). It is implementing a comprehensive strategy for tackling climate change in Australia. The strategy is built on three pillars: reducing Australia's carbon pollution; adaptation to unavoidable climate change; and helping to shape a global solution.

The Victorian Government's Green Paper on Climate Change (2009), states that the Government's main objectives for the stationary energy sector into the future are to:

- *"Support the provision of an efficient, reliable, safe and secure energy system that recognises and addresses the need to reduce greenhouse gas emissions*
- *Maintain access to energy by ensuring a fair, competitive market*
- *Promote energy supply and use that is environmentally sustainable and less greenhouse intensive*
- *Address planning barriers to the promotion and uptake of low carbon energy forms."*

The Green Paper posed the question:

"What might Victoria's energy system look like in 10 years?"

With the following response:

"*Coal-fired generation will still provide the majority of our electricity. But new generation will be much more efficient, often emitting less than half of old generators"*.

The objectives of the Green Paper are reflected in the Victorian Government's recently released Future Energy Statement (June 2010), which will guide the transformation of the State's energy sector. The Future Energy Statement recognises expected growth in low emissions forms of fossil fuel energy and subsequent benefits including economic benefits to regional Victoria, the creation of new opportunities in energy production and improving energy supply security.

Dual Gas Response to Commonwealth and State Policy Direction

Dual Gas believes it can assist in reducing Australia's carbon pollution directly in this Dual Gas Demonstration Project and indirectly by assisting HRL to commercialise and further develop its IDGCC technology. HRL, as owner of the IP, may, if the technology is successful, licence its IP to project developers (including Dual Gas) for new projects within Latrobe Valley, or other suitable areas within Australia or globally.

The Dual Gas Demonstration Project (DGDP) responds directly to the Commonwealth Government and Victorian Government climate change strategies. The key features being[†]:

- The project average greenhouse gas emissions intensity is expected to be in the range of 0.73 to 0.78 tonnes CO_2-e/MWh over the life of the project, depending on the quantity of natural gas consumed. This complies with the Victorian Government's Victorian Climate Change White Paper target intensity of 0.8 t CO_2-e per MWh for new power stations; it is approximately 31% to 36% lower than the current best performing Latrobe Valley brown coal power station (*i.e.*, Loy Yang A with a GGI of approximately 1.12 tonnes CO_2-e per MWh). Also, the average GHG emissions intensity of the DGDP is expected to be lower than any black coal power station currently operating in Australia (GGI range 0.80–1.00 tonne CO_2-e/MWh).
- The DGDP, which will also use dry cooling equipment, is expected to use around 75% less water per MWh than the best practise (in terms of water consumption) existing brown coal fired power station in the Latrobe Valley.

2.1.1.3. HRL's IDGCC technology development pathway

HRL's IDGCC technology is a process that combines the pressurised drying and gasification of brown coal with gas turbine combined cycle power generation.

This technology has been developed over a period of more than 20 years, initially prompted by the Victorian Government Natural Resources & Environment Committee inquiry (1985-88) into Electricity Supply & Demand Beyond the Mid-1990s.

Since initial development, more than $150 million has been spent on developing and proving the IDGCC technology. The IDGCC technology development pathway has included:

- process and economic modelling and laboratory-scale testing; and
- the development and operation of a 0.5MW Coal Gasification Demonstration Unit (CGDU) at Mulgrave, in the south-eastern suburbs of Melbourne. Initially the CGDU demonstrated the gasification of a range of coals. In more recent times it has been operated to supply a syngas stream for pre-combustion carbon capture trials.

[†] Comparison of DGDPS performance against existing power stations and 'best practice' power generation technology, is determined using publicly available GGI data on a 'sent out' basis and calculating a 'generated' GGI using an estimate for electricity consumed by the power station.

- the development and operation of a 10MW Coal Gasification Development Facility (CGDF) near Morwell in the 1990s in Latrobe Valley. The CGDF successfully demonstrated the IDGCC process from coal preparation through to syngas combustion in a grid-connected 5MW gas turbine and Heat Recovery Steam Generator.

This proposed development is the fourth stage of the IDGCC technology development pathway and aims to demonstrate the IDGCC technology at commercial-scale.

If this fourth stage is successful, the fifth technology development stage is expected to be the combining of the IDGCC technology with carbon capture (CC). On 20 January 2010, the Victorian Government announced "Cleaner Energy Projects Share in up to $29 Million". This announced that HRL will be provided with a grant of up to $3.5 million to investigate the feasibility of a pre-combustion CO_2 capture project.

The IDGCC technology has the potential to improve the efficiency of resource use (coal and water) in power generation from brown coal compared to existing coal fired power generation in the Latrobe Valley.

2.1.1.4. Benefits to Local and Regional Economy and Community

The Dual Gas Demonstration Project will also contribute to the local and regional economy directly through employment of additional labour (expected to be up to 350 contractors during construction and approximately 40 direct employees once operating). Additional employment will also occur through the purchasing of coal, gas, consumables, and maintenance and site services.

If commercially successful, the technology demonstrated may, over time, be deployed in the Latrobe Valley to provide the ongoing reliable production of base load electricity from Victoria's abundant brown coal resource resulting in a major reduction in CO_2 emissions and water consumption compared to the existing Latrobe Valley brown coal power generation operations. The technology has the potential to enable the State of Victoria to continue to have access to a low cost reliable energy supply in a carbon constrained world.

2.1.1.5. Government Support

The Project has support from both the Australian and Victorian Governments with funding of $150 million in total:

- The Australian Government has committed $100 million to the project as part of its Low Emissions Technology Demonstration Fund (LETDF). LETDF provides funding to help Australian firms commercialise world-leading low emissions technologies. The objective of the LETDF is to demonstrate the commercial potential of new energy technologies or processes or

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the application of overseas technologies or processes to Australian circumstances to deliver long-term large-scale greenhouse gas emission reductions, through:

- The demonstration of the commercial potential of new energy technologies or processes; and
- The application of overseas technologies or processes to Australian circumstances.

The LETDF is managed by the Commonwealth Department of Resources, Energy and Tourism.

- The Victorian Government has committed $50 million through its Energy Technology Innovation Scheme (ETIS). The ETIS scheme is a response to the significant environmental challenges to the economic advantages Victoria currently derives from utilisation of its very low-cost brown coal resources. The State accounts for 22 percent of Australia's greenhouse gas emissions, and approximately 52 percent of these arise from the use of brown coal for electricity generation in the State. As the key stakeholder for the Victorian community, the Government is seeking to deliver two key policy objectives:
  - To contain greenhouse gas emissions from the supply and use of energy in order to develop over time a sustainable energy sector; and
  - To drive improvements in energy efficiency and facilitate investment in sustainable energy supply sources to support the continuing competitiveness of Victoria's industrial base.
- The Victorian Government is implementing the ETIS to position Victoria for least-cost solutions for stationary energy supply and use in a carbon-constrained world (DPI, 2010).

2.1.2. Site Location and Description

The proposed Dual Gas Demonstration Project site is located approximately one kilometre south of the Morwell township, which is approximately 150 km southeast of Melbourne's Central Business District (Figure 1).

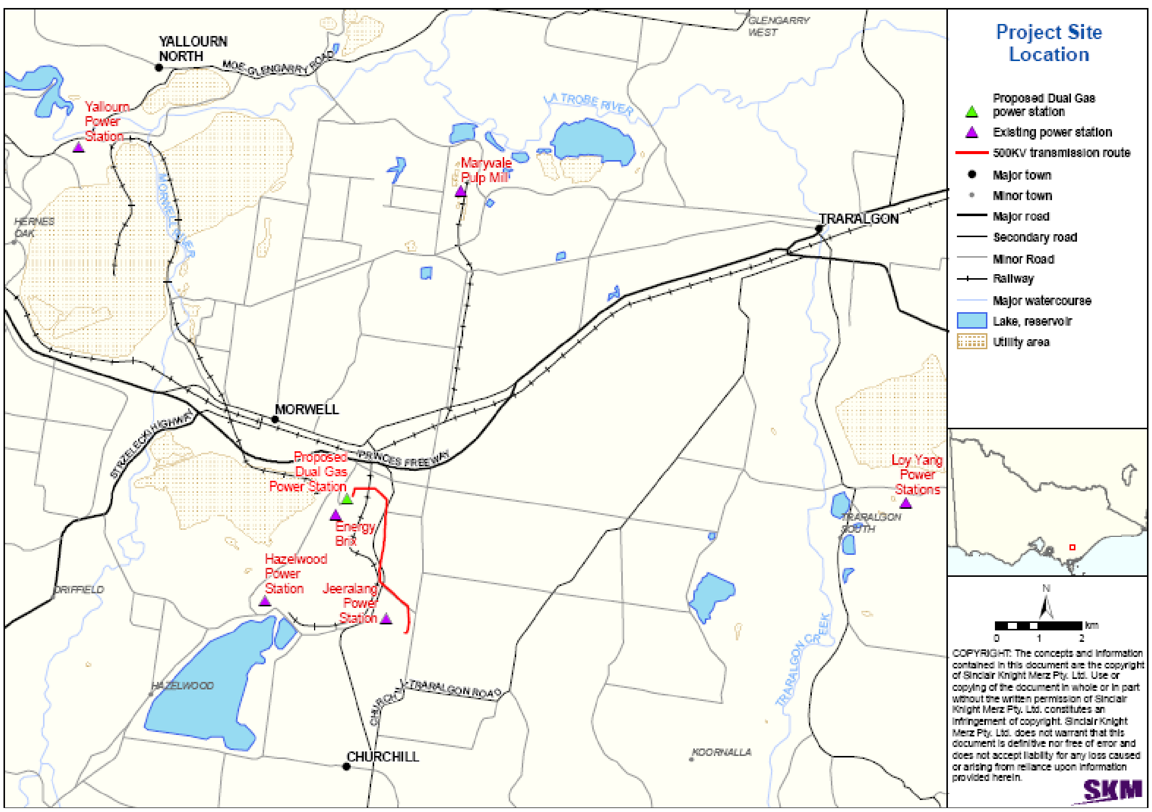
The proposed demonstration power station site, which is subject to this Works Approval application, is located on an existing open- air briquette storage area and car park within the Energy Brix Australia Corporation (EBAC) site at Commercial Road, Morwell as shown in Figure 2. The EBAC site is bounded to the west by Monash Way and to the north by Commercial Road.

The major part of the site is located within Special Use Zone – Schedule 1 (Brown Coal) (SUZ1) under the Latrobe Planning Scheme. The northwest corner of the site, in which an office building and a part of a car park associated with the proposed demonstration power station will be located, is within Industrial Zone 1 (IN1Z).

The proposed demonstration power station site has been highly disturbed and is sparsely vegetated and limited to lawn, grasses and scattered mature trees located on access road verges and the edge of the existing car parking area. Most of the subject site has been used as a briquette storage area for the past 50 years and is covered in dry coal. The western end of the site has been partially excavated to create a hardstand car park. A power line easement is located within the site. There are no other encumbrances, restrictions or registered agreements which may provide an impediment to the project.

It is expected that the current disturbed site will be further excavated and cleaned up to provide a level bench, suitable for the construction of the Dual Gas Demonstration Project, before being leased to Dual Gas Pty Ltd.

The site will be accessed via a private road off Commercial Road.



▪ **Figure 1: Project Site Location**

Figure 2: Proposed Demonstration Power Station Site

2.1.3. Surrounding Land Use

The proposed demonstration power station site is located greater than 1km from residences and the Morwell urban centre. The land immediately surrounding the demonstration power station site is zoned SUZ1 and is owned by EBAC, with usage as follows:

- North - a grassed area that was previously used as an ash pond for the existing EBAC power station. This ash pond was capped and rehabilitated in 1960's;
- South - briquette manufacturing and 190MW co-generation plant;
- East – briquette loading and storage facilities; and
- West – car park.

These uses are proposed to continue on the site and are not expected to be affected by the proposed development. The EBAC site is bounded to the north by Commercial Road, Princes Freeway and Gippsland Railway Line. This infrastructure geographically and visually separates the industrial and agricultural land uses of the surrounding area from the Morwell Township and commercial precinct to the north.

To the west, the EBAC site is bounded by Hazelwood Drive. The land further west is zoned IN1Z and there is the Statewide Autistic Services' Alfred Murfey Centre (formerly the SECV LV Control Centre building) used for training and further west again is the Hazelwood open cut brown coal mine. To the North West, there is an office complex (formerly the SECV's Generation Headquarters building) and the Powerworks Energy Technology and Visitors Centre.

The land adjacent to the south of the EBAC site is occupied by the Hazelwood Power Station, owned by International Power Australia Pty Ltd.

The surrounding area to the east is included in an IN1Z and provides for industrial and agricultural land uses in an open and flat landscape. The area has been developed for industrial and agricultural land use including Australia Char Pty Ltd (char and barbeque fuel manufacturing), Morwell Terminal Station, Seshurst Four Hundred and Fifty Pty Ltd, and Reeftec Pty Ltd. The undeveloped industrial land in this area is earmarked for a logistics precinct to service the region. There are numerous high voltage transmission lines and a major gas pipeline intersecting the area.

2.1.4. Project Description

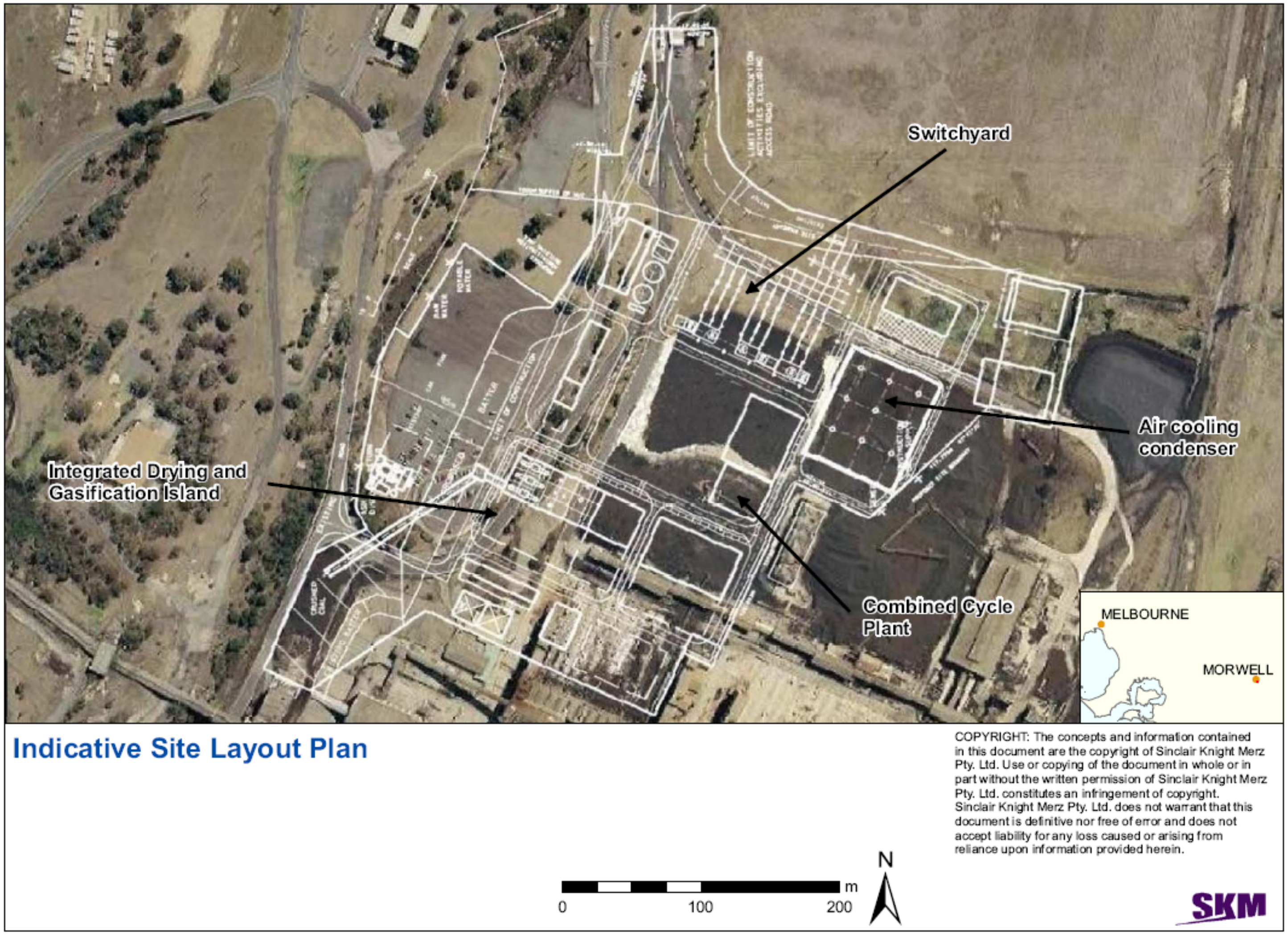
2.1.4.1. Key demonstration power station components

Key components of the proposed demonstration power station site comprise:

- 2 integrated drying and gasification (IDG) plants including;
    - Syngas filtration and conditioning plant;

- Air compressors;
- Char and ash combustion plant;
- By-product drying and crystallisation plant
- 2 combined cycle power plants:
  - 2 gas turbines (GTs);
  - 2 heat recovery steam generators (HRSGs);
  - 1 steam turbine and generator (STG);
  - 1 air cooled condenser (ACC);

Subject to final design by the Engineering Procurement Contractor (EPC), Figure 3 shows the proposed locations of the key plants, buildings and infrastructure connection points.



- **Figure 3 Site Layout Plan**

The major components listed above will be manufactured offsite and transported to the site for assembling and erection.

The height of the combined cycle power plant stacks is estimated to be approximately 80 metres, with the final height to be determined mainly by technical and air quality requirements. The other major structures proposed are the Air Cooled Condensers, with a height of approximately 47 metres and the Steam Turbine Generator Hall, with a height of 31 metres.

The coal feed rate into the IDG plants will be approximately 500 tonnes per hour.

The following connections to utilities and minor construction activities will be conducted as part of the construction activities associated with the proposed demonstration power station development:

- Installation of ash water disposal pipeline from the char burner to the existing ash management facility located approximately 700 metres south of the proposed demonstration power station site (via EBAC owned land);
- Extension of coal supply conveyor from the EBAC raw coal bunker adjacent to the south west corner of the proposed demonstration power station site;
- Tap into an existing main water supply pipeline located approximately 100 metres west of the proposed demonstration power station site (via EBAC owned land);
- Connection of utilities, including electricity and gas supplies (a new off-site major gas pipeline is expected to be the subject of a separate Works Approval application by another proponent. It is expected that Dual Gas will be one user of the new pipeline);
- Construction of administrative building;
- Construction of additional car parking facilities;
- Construction of proposed site drainage and water management systems; and
- Security fencing and landscaping.

The construction of all plant and utilities listed above, except for the Integrated Drying and Gasification Plant No. 2, is expected to be completed and commissioned to supply full generation capacity to the grid by 2013. The construction of the Integrated Drying and Gasification Plant No. 2 is expected to be completed and commissioned by 2015, subject to the demonstration of acceptable performance from the Combined Cycle units and Integrated Drying and Gasification Plant No. 1.

2.1.4.2. Coal Sources

It is expected that coal will be initially sourced from an existing mine adjacent to the proposed demonstration power station site. The coal will be delivered from the mine to the EBAC site via existing conveyors, then to the proposed demonstration power station site via a new conveyor. Coal may need to be sourced from other Latrobe Valley brown coal mines if the adjacent mine was to cease operating or if longer term commercial arrangements cannot be agreed. At the time of this Works Approval application, it is assumed that coal will be sourced after 2016 from the Yallourn North Extension coal mine, which is located approximately 15 km north of the proposed demonstration power station site, and delivered to the existing EBAC coal ditch bunker by road trucks.

2.2. Cost of works and application fee

The estimated cost of works associated with the construction of the Dual Gas Demonstration Project is above $750 million. This project therefore falls into the category "$100 million and greater" from the Table 1 – Cost of works and application Fee of Appendix A of the *Works Approval Guidelines, Publication 1307.2, July 2010*. The Works Approval application fee for this project is therefore estimated to be $52,605.

2.3. Proposed dates

The DGDP involves a two phase construction process and a subsequent two phase operational timeline, as shown in the table below. This Works Approval application presents the environmental impacts of the full power plant (Stage 1 and Stage 2), thereby assessing the worst case scenario.

Stage	Description	Start construction	Start operation
Stage 1	Two Combined Cycle Power Plants and Integrated Drying and Gasification (IDG) Plant No.1	2011	2013
Stage 2	Integrated Drying and Gasification (IDG) Plant No.2	2014	2015

3. APPROVALS

3.1. Need for Works Approval

The proposed demonstration power station is defined as a Scheduled Premise (K01 – Power Stations) under the *Environment Protection (Scheduled Premises and Exemptions) Regulations 2007* as it generates electrical power from the consumption of a fuel at a rated capacity of at least 5 megawatts.

Pursuant to Section 19A of the *Environment Protection Act 1970*, a Works Approval is required for the development of the proposed demonstration power station and this has been confirmed by the EPA.

3.2. Planning and Other Approvals

3.2.1. Planning Permits

Dual Gas has also been consulting with the Latrobe City Council. The Council has confirmed the following planning permits are required under the Latrobe Planning Scheme:

- The *use* and *development* of land for a transmission line (*Utility Installation*) pursuant to the Industrial 1 Zone (IN1Z), Farming Zone, Road Zone Category 1 which affect the proposed transmission line corridor;
- The *development* of land where the transmission line affects the Special Use Zone – Schedule 5 and Environmental Significance Overlay- Schedule 1 (Urban Buffer) (ESO1), State Resources Overlay – Schedule 1 and Design and Development;
- The *development* of an office and earthworks (site preparation) associated with the demonstration power station (*Industry*) pursuant to the IN1Z;
- A waiver or reduction in car parking (Clause 52.06) and bicycle storage facility(Clause 52.34) requirements; and
- Removal of native (ESO1 and Clause 52.17) and non-native vegetation .(ESO1)

Planning approval is not required for the *use* of land for the demonstration power station (*Industry*) under the SUZ1 of the Latrobe Planning Scheme where the site is at least 1 km from land in a residential or business zone or land use for a school or hospital. In addition, planning approval is not required for the *development* of land (including buildings and works) associated with *Industry* pursuant to the SUZ1 and ESO1 which complies with a Works Approval granted under the *Environment Protection Act 1970*.

Accordingly, Dual Gas will submit planning permit applications for the Project to Latrobe City Council including:

1) The development of an administration building, car park, non-native vegetation removal, reduction of car parking and waiver of bicycle storage facility requirements associated with the proposed demonstration power station on behalf of Dual Gas. The subject land is located outside the proposed demonstration power station site.
2) The removal of non-native vegetation located within the demonstration power station site necessary for site establishment works on behalf of EBAC.
3) The use and development of a transmission line, native and non-native vegetation removal and waiver of car parking requirements associated with the transmission line located outside the EBAC site on behalf of Dual Gas.

The first two applications were lodged with the Latrobe City Council on 24 March 2010. The third application will be lodged once the preferred transmission line route is determined.

3.2.2. EES Referral

An Environment Effects Statement Referral under the *Environment Effects Act 1978* was required because the proposal triggers one of the referral criteria set out in the Ministerial Guidelines, specifically "*potential greenhouse gas emissions exceeding 200,000 tonnes of carbon dioxide equivalent per annum, directly attributable to the operation of the facility*". The Project was referred to the Minister for Planning for his advice as to whether an Environment Effects Statement (EES) is required. The EES Referral was formally accepted by Department of Planning and Community Development (DPCD) on 2 October 2009 and a decision that no EES was required was made by the Minister for Planning on 23 November 2009.

The reasons cited by the Minister for Planning as to why an EES is not required are:

1. *The construction of the proposed power station would not have significant adverse effects on environmental values, as it would be located on an existing industrial site with no significant landscape, waterway, biodiversity or cultural heritage features.*
2. *The proposed power station site is already zoned under the Latrobe Planning Scheme to provide for brown coal mining, electricity generation and associated uses, and the establishment of a new energy generation facility is unlikely to significantly increase off-site hazards relative to existing industrial activities that are adjacent to the site.*
3. *Potential environmental effects of operating the power station, including opportunities to minimise greenhouse gas emissions, resource use, waste, as well as to minimise adverse effects with respect to air quality and noise, can be adequately assessed under the Environmental Protection Act 1970. Best practice approaches will need to be applied in addressing these aspects.*
4. *The proposed technology for power generation using a combination of gasified brown coal and natural gas, if commercially viable, is likely to significantly reduce the greenhouse gas intensity of power generation, as well as water use, relative to brown coal-based power technologies currently in use in the Latrobe Valley. The proposed technology will also*

facilitate the implementation of pre-combustion capture of carbon dioxide when infrastructure for its transport and storage is commercially available.

5. *The proposed powerline to transmit electricity from the power station site to the existing Hazelwood Transmission Station is unlikely to cause significant adverse effects on environmental values, including landscape, biodiversity and cultural heritage, due to the overhead technology, the relatively short length of the powerline and the extensive modification of the local environment by both agriculture and industrial land uses.*

3.2.3. Civil Aviation Safety Authority Referral

Referral to the Civil Aviation Safety Authority under the *Commonwealth Airports Act 1996* is required. A Plume Rise Assessment is currently being undertaken, following which the Aviation Hazard Assessment will then be carried out and Referral to the Civil Aviation Safety Authority made by August 2010.

3.2.4. Cultural Heritage Management Plan

A Cultural Heritage Management Plan under the *Aboriginal Heritage Act 2006* is required for the transmission line site. Work on this will start once the final transmission line route is confirmed.

3.3. Existing EPA approvals (if any)

Nil [Dual Gas Pty Ltd is a new special purpose company].

4. ENVIRONMENT AND COMMUNITY

4.1. Track record

Dual Gas Pty Ltd is a new special purpose company and as such has no track record with the EPA.

The parent company, HRL Limited operates the Morwell Power Station via a company called Energy Brix Australia Corporation (EBAC). HRL acquired EBAC in 1996 and since that time there have been no relevant offences or enforcement actions related to this site.

A number of environmental improvements have been made to the EBAC site over the past five years. These have included:

2005:

- Major upgrade of EDP (dust) controllers
- Environmental Management Plan and Environmental Improvement Plans completed.

2006:

- Recycling of water from the settling pond to the Power Station (approx 4.6ML/ day)

2007:

- Electrostatic Dust Precipitator (EDP) plates were replated at a cost of $550k to improve efficiency in removing particulates.
- Changed fuel oil from "heavy marine fuel" to a "recycled waste oil".

2008:

- Settling pond dredged to increase retention time and improve discharge water quality

2009:

- Replating of No 5 EDP completed.
- Reduction of 19% of total water usage since 2006 due to recycling.

4.2. Key environmental considerations

After consultation with the EPA, the key environmental issues related to the DGDP have been identified as Greenhouse Gas Emissions, Air Quality, Water Usage and Noise. These are further detailed in the sections below and in Sections A to I.

4.2.1. Greenhouse Gas Emissions

A key measure of greenhouse gas (GHG) emissions performance is the greenhouse gas intensity (GGI), commonly reported in units of tonnes of carbon dioxide-equivalent emissions emitted per

MegaWatt-hour of electrical energy generated; *i.e.*, shortened to 'tonne CO_2-e / MWh'. Although the DGDP will use brown coal as a primary fuel, the GGI of the electricity transferred to the electricity transmission grid from the proposed development is much lower than that from a conventional brown coal-fired power station. This is due to HRL's IDGCC power generation technology to be utilised by the proposed DGDP; The IDGCC Technology is a means of using brown coal in a high efficiency gas turbine combined cycle power generation system. The coal is first dried, then gasified in a fluidised bed gasifier, and then the syngas (coal gas) is cooled, cleaned and burned in the gas turbine to produce power. The hot exhaust gas from the gas turbine is further used in a heat recovery steam generator to produce steam to drive a steam turbine to produce additional power. Normal operations by the DGDP are expected to use quantities of syngas and natural gas. In summary, the GGI of the new DGDP will be significantly less than for a power station that combusts brown coal directly.

The annual GHG emissions by the DGDP will be influenced by a number of factors including the coal supply quality and the quantity of natural gas consumed. The operations will also be influenced by the state of the electricity, gas and carbon markets. A functioning carbon market assumes a CPRS or equivalent is adopted by the Australian government.

A number of operating scenarios for the DGDP have been modelled to determine expected GHG emissions performance. The annual GHG emissions are expected to range from approximately 3.0 million tonnes to approximately 3.2 million tonnes. The plant is fuelled by brown coal, with some supplementary firing with natural gas.

The theoretical maximum GHG emission by DGDP is 4.2 million tonnes CO_2-e per annum; however this is very unlikely to occur given the expected normal operating and market conditions. This assumes that the gasifiers run at full output for the entire year, with the gas turbines fired 85% of the time on syngas and fired 10% of the time on natural gas (with 5% downtime for the gas turbines). The actual level of emissions within any given year will depend upon the capacity factor of the power generation plant and the relative quantities of the fuels used – influenced by a range of market factors including:

- Price of electricity, influenced by electricity demand and supply factors;
- Cost, quality and usage of natural gas;
- Cost and quality of coal; and
- Cost of carbon permits.

The GHG emissions intensity of the DGDP is expected to range between approximately 0.73–0.78 tonne CO_2-e/MWh over the life of the project. This is ("as generated" data):

- Lower than the Victorian Government's Victorian Climate Change White Paper target intensity of 0.8 t CO_2-e per MWh for new power stations;
- Significantly better (lower) than any other brown coal-based power generation plant in the Latrobe Valley (GGI estimates ranging from approximately1.12–1.40 tonne CO_2/MWh); and
- Lower than any current black coal-fired power generation plant operating within the NEM, (GGIs ranging from approximately 0.80–1.00 tonne CO_2-e per MWh.

In addition, the DGDP will be built to enable the potential retro-fitting of pre-combustion CO_2 capture technology, (when commercially viable), providing future options to further reduce the demonstration power station's CO_2 emissions.

The successful demonstration of the IDGCC technology at commercial scale will provide a technology development pathway for lower GHG emissions intensive power generation from brown coal. The IDGCC technology, when combined with CO_2 capture and storage technologies, is expected to have a GHG emissions intensity lower than current natural gas-fuelled power generation by CCGT technology.

Operation of the DGDP with the introduction of the Commonwealth Government's proposed Carbon Pollution Reduction Scheme (CPRS) may displace other power generation with higher greenhouse intensity under the operation of the National Electricity Market (NEM) with a price on carbon. Overall, this can be expected to lower GHG emissions per unit of electrical energy generated for power generation in Victoria, while efficiently utilising the State's abundant resources of brown coal.

4.2.2. Air Quality

Overview

The key pollutants associated with operation of the Dual Gas Demonstration Project are oxides of nitrogen (NO_x) and sulfur dioxide (SO_2) with emissions of particulate matter found to be negligible. SO_2 and NO_x emissions are significantly lower than from conventional brown coal-fired power stations.

To ensure compliance with the State Environment Protection Policy - Air Quality Management (SEPP- AQM) Schedule A and Schedule E, a detailed air quality assessment utilising air dispersion modelling of point source emitters has been undertaken with an alternative modelling methodology and input data approved by EPA Victoria. The air quality assessment report is provided as Appendix C.

The assessment involved dispersion modelling of air quality effects from point source emitters to determine cumulative ground level concentrations of nitrogen dioxide (NO_2) and SO_2 resulting from the proposed demonstration power plant. In the cumulative assessment other key air pollutant sources in the Latrobe Valley were accounted for; i.e. Energy Brix, Hazelwood, Yallourn, Loy Yang A and Loy Yang B power stations and Maryvale Paper Mill, utilising the advanced non-steady state model CALPUFF Version 6.262.

Modelled 99.9th percentile 1-hour ground level concentrations of NO_2 and SO_2 as predicted by CALPUFF are below the SEPP-AQM 1-hour Design Ground Level Concentration (GLC) of 0.10ppm[‡] and 0.17ppm[§] respectively.

In conjunction with other point sources within the Latrobe Valley, the highest 99.9th percentile 1-hour average modelled value for NO_2 is 0.05 ppm and occurs approximately 2 km south south-west of the proposed demonstration power station. The highest 99.9th percentile 1-hour average modelled value for SO_2 in conjunction with other Latrobe Valley sources is 0.15 ppm and occurs approximately 13 km east of the proposed demonstration power station. Also, the 99.9th percentile modelled GLCs at various discrete receptor locations, including current Latrobe Valley Air Monitoring Network (LVAMN) stations, are below the relevant design criteria.

NO_x emissions

NO_x emissions are expected to be just above the Schedule E limit of 0.07 g/m^3 for gaseous fuels corrected to 15% O_2 (dry). This may be the case particularly for periods of operation of the duct burner (syngas and natural gas operation).

The DGDP is to employ specific technologies to reduce NO_x formation, including ammonia scrubbing of the syngas with a design of 95% ammonia removal (to reduce fuel NO_x). Due to the use of the lower calorific value (compared with natural gas) syngas in the gas turbine, diffusion combustion technology must be used, and as such the Dry Low NO_x burners normally employed for combustion of natural gas are unable to be used. As such, to reduce thermal NO_x emissions under natural gas operation, steam injection is used, resulting in a trade-off between efficiency and NO_x emissions.

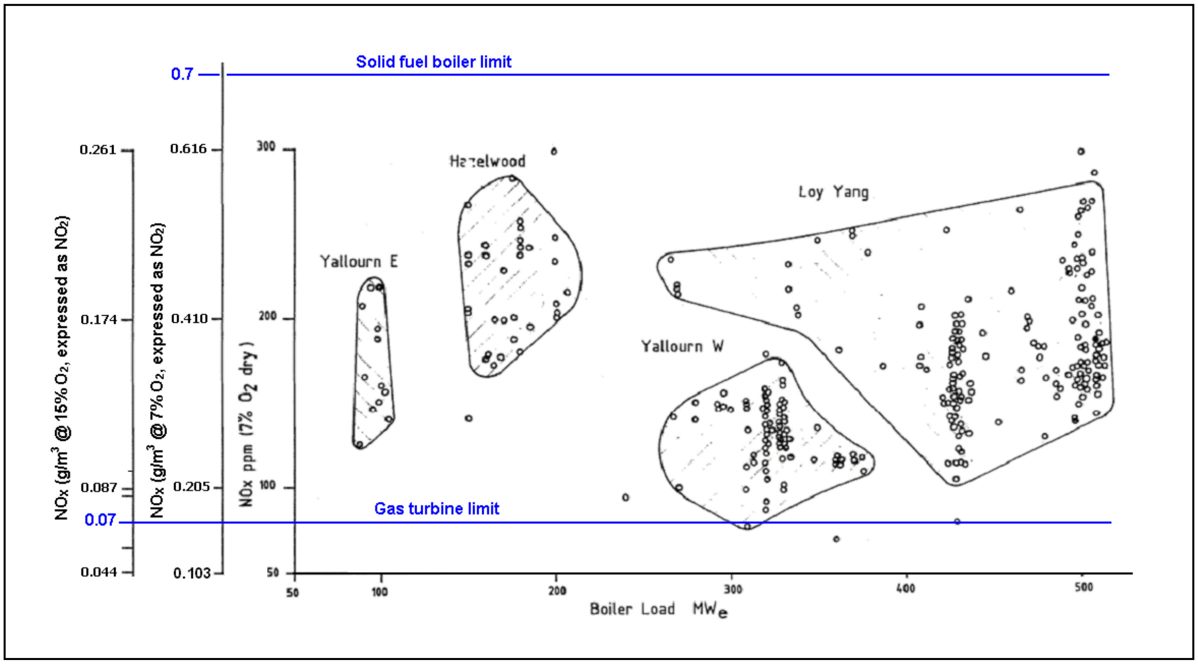
With respect to the classification of the DGDP emissions under Schedule E, while the DGDP is a syngas and natural gas-fired power station, it is emphasised that a main energy source is a solid fuel. A brief analysis on the DGDP in the context of brown coal use is provided in the following paragraph.

The Schedule E NO_x limit for solid fuels e.g. conventional brown coal fired power plant, is 0.7 g/m^3 corrected to 7% O_2 (dry), which is substantially higher than that for gaseous fuels. Figure 4 shows

[‡] 0.1 parts per million NO_2 or 0.19 mg/m^3 (SEPP-AQM).

[§] 0.17 ppm SO_2 or 0.45 mg/m^3 (SEPP-AQM).

published (McIntosh, et al., 1986) NO_x data from the Latrobe Valley brown coal fired power stations. It is emphasised that the NO_x emissions from the DGDP (using syngas generated from brown coal and natural gas) are expected to be lower than current, conventional brown coal fired technology.



▪ **Figure 4: Brown Coal Fired Power Station NO_x Limits**

Plume dispersion modelling (see Appendix C) indicated that the ambient air quality criteria specified in Schedule A of the SEPP for NO_x are predicted to be easily met.

In conclusion, as the main energy source is a solid fuel, and for this First Of A Kind (FOAK) demonstration power station, it is Dual Gas's preference for the DGDP to be classified similarly to other brown coal fired plant in regards to NOx emission levels.

Particulate Matter

PM_{10} emissions from the site were assessed in conjunction with other Latrobe Valley sources and found to have negligible impact (HRL, 2010a). The proposed syngas-fuelled DGDP ensures contributions of particulate matter will be insignificant from this site. Emission rates of PM_{10} from the proposed DGDP are expected to be 2 g/s from the Char Burners and 6 g/s from the CCGT units. These PM_{10} emissions were modelled in conjunction with other Latrobe Valley PM_{10} sources and found to have negligible impact, with cumulative 99.9th percentile modelled concentrations not exceeding 20% of the PM_{10} Design Criteria (HRL, 2010a).

Also, disregarding the effects of bushfire/planned burning activities, measurements in Latrobe Valley have shown that the State Environment Protection Policy (SEPP) Air Quality Objective for PM_{10} (50μg m^3) is easily met (Black & Delaney, 2004).

Class 3 Indicators

An assessment of Class 3 indicators has been undertaken (see Appendix F) which shows that the addition of the DGDP to the air shed should not significantly impact the ground level concentrations of Class 3 indicators in the Latrobe Valley with relevant SEPP Design Criteria not being exceeded.

Construction Related Air Emissions

Construction of the DGDP has the potential to cause air quality (e.g. dust) impacts on the surrounding environment. Appropriate dust suppression methods will be employed throughout construction and detailed in the construction environmental management plan (CEMP).

4.2.3. Water Usage

Up to 2 GL/yr is expected to be required during operation of the proposed demonstration power station. Following discussions with DSE and DTF, Dual Gas has been provisionally provided a 2 GL/yr water allocation from Blue Rock Dam, with a reliable yield of 95%. This allocation is to be supplied from the State Electricity Commission Victoria (SECV) unused entitlement. The impact of this additional water usage was assessed in Appendix A (Water Use Desktop Assessment). It was concluded that compliance with the currently legally enforced environmental flow requirements for the Latrobe River, described in Southern Rural Water's Bulk Entitlement conversion order, will not be affected.

A breakdown of the main areas within the plant that will consume water and estimated volumes is provided in Section B1 of this document.

The DGDP is expected to use about 75% less water per MWh than the best practice (in regards to water consumption) existing brown coal fired power station in the Latrobe Valley, namely Loy Yang B power station. Loy Yang B uses 1.96 ML/MWh (LYB Power Station Environmental Performance Report 2006), compared with an expected 0.48 ML/MWh for DGDP. The average water consumption for all brown coal generators in the Latrobe Valley is 2.31 ML/MWh[**].

[**] Data sourced from the following reports:

- International Power Hazelwood, 2006. *Social and Environment Report 2006*
- Loy Yang Power, 2008. *Sustainability Report 2007*
- International Power Australia, 2006. *Loy Yang B Power Station Environmental Performance Report 2006.*

Around 40% less water per MWh is expected to be the direct result of using the IDGCC technology, as it is applied to the DGDP.

A second key design selection contributing the remaining (about 35%) less water per MWh is the use of Air Cooled Condenser (ACC) technology. ACC has been selected over a Wet Cooling System as the primary cooling technology for cooling of condensate in the steam cycle (for a comparison of the two systems see Section 5.3.2). Although the use of ACC technology will slightly lower the plant performance during periods of high ambient temperature and requires a higher capital cost, it minimises water consumption by the Dual Gas Demonstration Project. Further water efficiency measures are detailed in Section B2 of this document.

Under CPRS, if the demonstration power station displaces some existing brown coal fired power station generation, it is anticipated that there would be an overall decrease in fresh water consumed by the Latrobe Valley brown coal fired electricity generators.

During the construction phase, the water requirement has been estimated at 20 ML/yr. This volume during construction is negligible in relation to both existing entitlements in the Latrobe Valley and river flows.

4.2.4. Noise

The siting and design of the proposed demonstration power station aims to ensure that the noise effects of the demonstration power station on sensitive land uses will be minimal in order to achieve legislative objectives. The site is located in an existing industrial environment (in close proximity to existing noise sources) greater than 1km from the closest residential and business area. This greatly reduces the risk that any potential noise emissions from the construction or operation of the plant will significantly affect community amenity.

A detailed noise assessment has been undertaken to ascertain the significance of the impact and to ensure that the demonstration power station is designed and developed to comply with best practice guidelines stipulated by the EPA. This includes the most current version of the draft State Guidelines into assessing acceptable noise levels from industrial premises “Noise From Industry in Regional Victoria (Publication 1316, December 2009)” and methodology for determining background noise criteria at the nearest sensitive receivers through the State Environment Protection Policy No. N-1 “Control of Noise from Commerce Industry and Trade”.

The assessment identified two residences in proximity of the proposed demonstration power station to undertake seven continuous days of background noise measurements in accordance with EPA Policy N-1 including:

- TRUenergy, 2007. *TRUenergy Yallourn Social and Environmental Performance Summary*.

- Residence One - 1.3 km north-west of the demonstration power station on the outskirts of the town of Morwell
- Residence Two - 2.5 km south-east of the demonstration power station in a rural setting

Both residences were identified as a suitable representation of the typical ambient noise levels in the general area as well as being possible locations at which an impact might occur due to the operation of the demonstration power station.

Results from the worst case scenario of predicted noise emissions from the demonstration power station as identified at the two residences indicate overall compliance with the noise level criteria at Residence Two. Residence One indicates that there is a potential breach of compliance for the night criteria by approximately 5.5 dBA. Whilst this discrepancy in noise levels is significant, the expected noise emission from the demonstration power station has been ascertained using conservative inputs and it will be necessary to verify the Sound Power Level data prior to committing to any noise mitigation program.

To achieve compliance with the EPA noise limit criteria, potential noise mitigation measures have been identified which can feasibly lower the total sound power level to the required EPA noise limit criteria (this is described in more detail in Section 7.4).

Further information on the noise modelling methodology and results is outlined in section H of this document.

4.3. Community engagement

4.3.1. Stakeholder consultation activities undertaken

Dual Gas (or HRL) has consulted with various governmental agencies and other groups since 2005, when HRL was successful in attracting government support under the Victorian government's ETIS program and the Commonwealth government's LETDF program.

A number of stakeholder consultations have been undertaken by Dual Gas (or HRL) representatives to brief stakeholders on the proposed DGDP. The project has been generally well received at these stakeholder consultations and the major issues raised have been addressed in this Works Approval Application. Consultations over the past year are detailed below.

Australian Government Departments

- Department of Resources Energy and Tourism (DRET)
- Department of Climate Change and Energy Efficiency (DCCEE)

Australian Government Agencies

- Australian Energy Market Operator (AEMO)

Victorian State Government Departments

- Department of Primary Industries (DPI)
- Clean Coal Victoria (CCV)
- Department of Innovation Industry and Regional Development (DIIRD)
- Department of Planning and Community Development (DPCD)
- Department of Sustainability & Environment (DSE)
- VicRoads

Victorian State Government Agencies

- Gippsland Water
- EPA Victoria
- Victoria Police

Local Government

- Latrobe City Council

Local Community Groups

- Advance Morwell
- Gippsland Climate Change Network
- Latrobe City Climate Change Consultative Committee

Local Industry/Businesses

- Ecogen Energy
- International Power Hazelwood
- Loy Yang Power
- Power Works
- SP AusNet
- TRUenergy

Other

- Australian Industry Group
- Victorian Trades and Labour Council
- Latrobe Valley Trade Unions
- Neighbouring landholders
- Representative of local Gunai Kurnai group (cultural heritage assessment)
- Victorian Coal and Energy Conference held in Traralgon

4.3.2. Public consultation activities planned

Dual Gas is committed to conducting community consultation as an integral part of the works approval (WA) process for the development of the Dual Gas Demonstration Project. Further consultations will be conducted during the WA process.

4.3.2.1. Consultation Components

The following will form the basis of the consultation approach of disseminating information and responding to issues or concerns raised and seeking community feedback during the works approval process.

Individual discussions and information sessions

Face to face information/briefing/feedback sessions – these may be one on one meetings with individuals or as appropriate may involve a small number of participants or representatives of special interest groups. These will provide a forum for open and two way communication.

Project Web site

Dual Gas will establish a dedicated project website (www.dualgas.net.au) to share information on the project and the approvals process. It will also include an online enquiry form.

Introductory Project Flyer

This will provide a clear and concise overview and introduction to the project together with relevant information on the process and contacts for further information and will be made available on the Dual gas web site.

Project fact sheets

Fact sheets will be available during the public exhibition period and will also be used to provide updates on the project as it progresses. These will be developed as relevant and made available on the Dual Gas website.

Project announcements

These will take the form of public announcements on the project. This may include the development of articles/editorial for placement in newspapers, etc or media releases or public advertisements on the project as appropriate – providing an opportunity for comment or feedback.

Frequently Asked Questions

The FAQ flyers will aim to provide initial background information on the project and answer potential community and stakeholder concerns. These will be developed as relevant and made available on the Dual Gas website.

Project Information Line and e-mail

A Dual Gas telephone information line and Dual Gas e-mail address will be established to provide access to a two-way communication mechanism for queries and concerns raised regarding the project, to be appropriately noted and responded.

Stakeholder database, register of community issues and concerns and summary report

This will enable timely and more targeted responses and feedback to be developed on key areas of concern or emerging issues to be addressed from the consultation process.

SINCLAIR KNIGHT MERZ SKM

5. PROCESS AND BEST PRACTICE

5.1. Process and technology

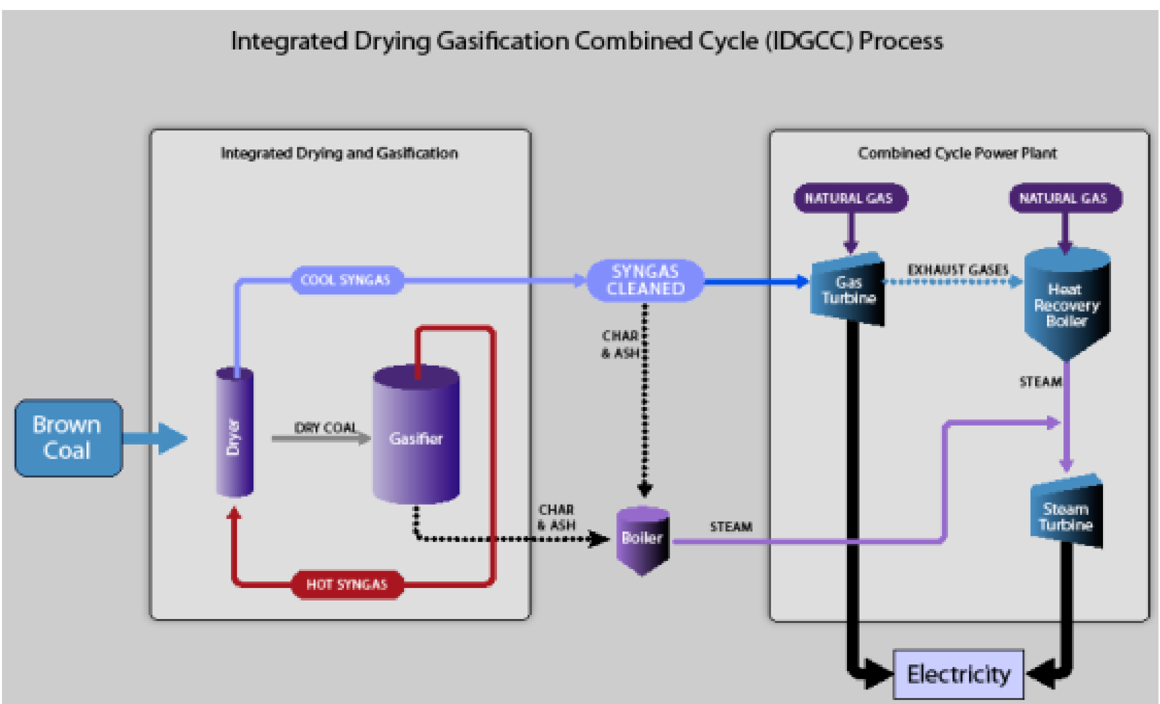
5.1.1. Introduction

The Integrated Drying and Gasification Combined Cycle (IDGCC) process integrates the drying of raw wet coal with coal gasification, syngas cleaning and gas turbine power technologies to produce electricity from low rank coals with significantly lower CO_2 emissions per MWh than current existing technologies. This integration of energy conversion processes provides more complete utilisation of energy resources and offers high efficiencies and reduced CO_2 levels.

This technology uses a combined cycle format with a gas turbine driven by the combusted syngas, while the exhaust gases are heat exchanged with water/steam to generate superheated steam to drive a steam turbine. The major components of this technology are therefore the two following units:

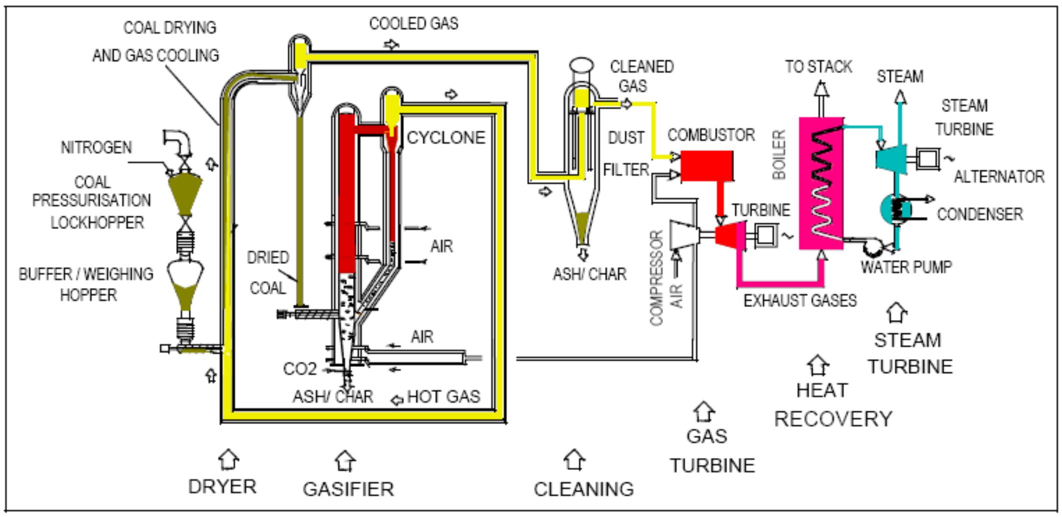
- Integrated Drying and Gasification (IDG) Plant (where the coal is dried and gasified); and
- Combined Cycle (CC) Power Plant (where the power is generated).

Figure 5 shows the main operational flows of the proposed demonstration power station using the IDGCC process.



- Figure 5: Integrated Drying Gasification Combined Cycle Process

The IDGCC Technology is a means of using brown coal in a high efficiency gas turbine combined cycle power generation. The coal is first dried, then gasified in a fluidised bed gasifier, and then the coal gas is cooled, cleaned and burned in the gas turbine to produce power. The hot exhaust gas from the gas turbine is further used in a heat recovery steam generator to produce steam to drive a steam turbine to produce additional power. A schematic of the process is shown below in Figure 6.



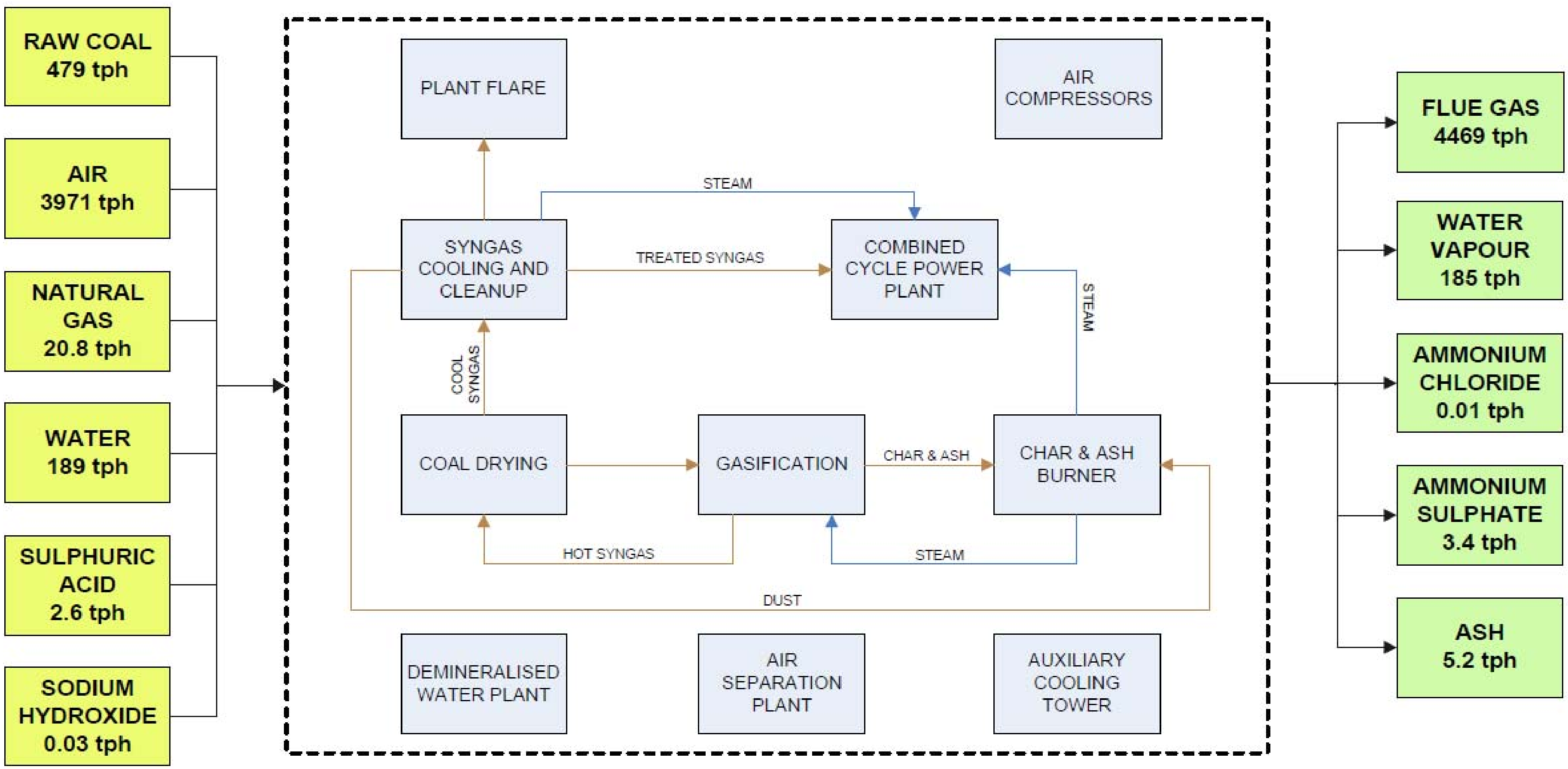
▪ **Figure 6: IDGCC Process Schematic**

Figure 7 and Figure 8 provides expected mass balance diagrams for two operating scenarios – two gas turbines operating on syngas; and two gas turbines operating on natural gas.

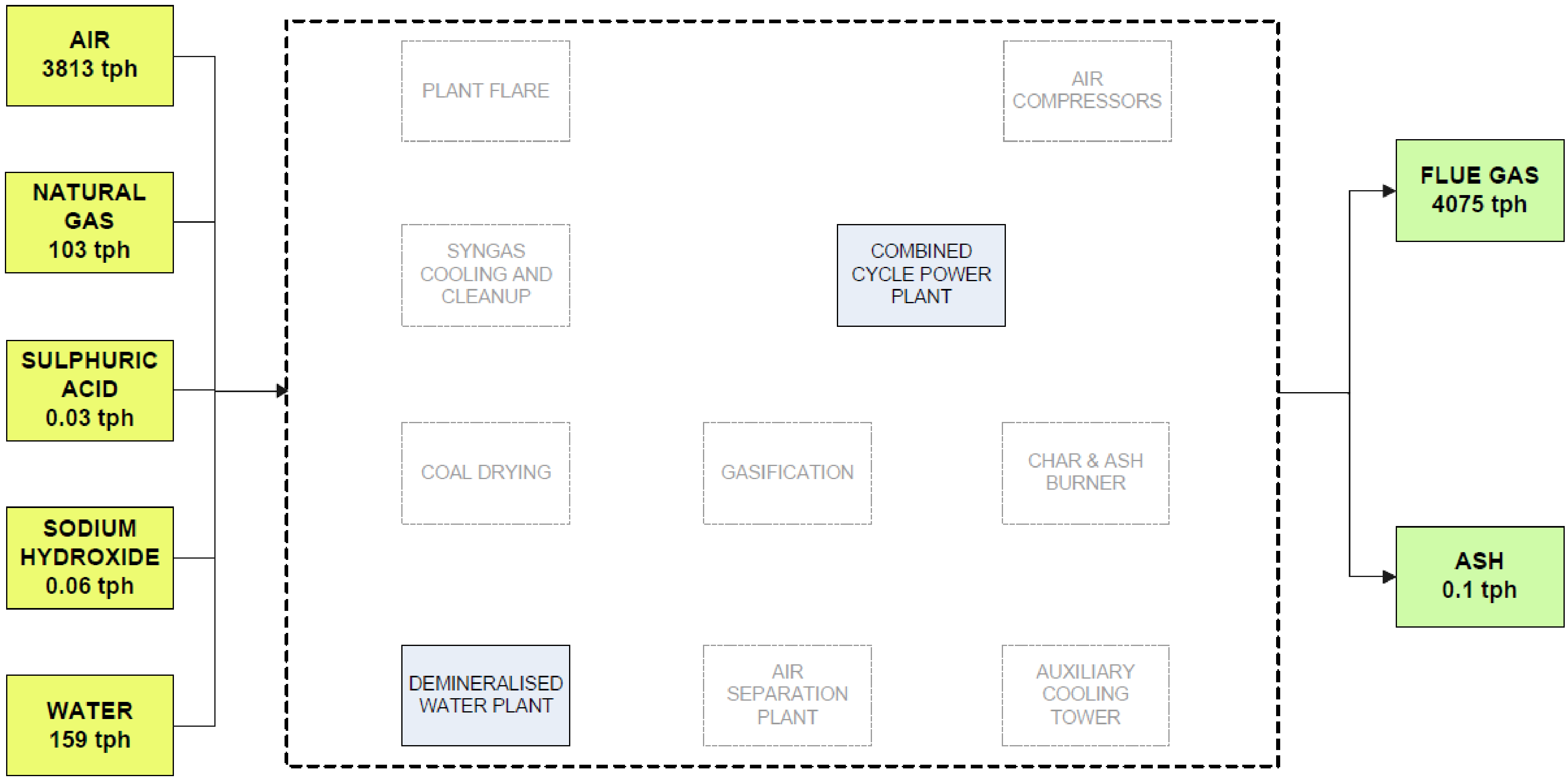
The overall water balance is provided in Section B1, including:

- the overall expected annual consumption in ML/year; and
- the expected hourly water consumption for two operating scenarios (with the two gas turbines operating on natural gas and on syngas respectively).

Water extraction from the process (and reuse) is described in Section 5.2.4.



- **Figure 7: Mass Balance Diagram (Case 1 - two gas turbines operating on syngas from Morwell coal, running 100% output with full duct firing on natural gas)**



- **Figure 8: Mass Balance Diagram (Case 2 - two gas turbines operating on natural gas, running 100% output with full duct firing on natural gas).**

5.1.2. Integrated Drying and Gasification Plant – Syngas Production

Syngas for use in the gas turbines will be generated by the IDGCC technology, where:

- Coal is dried under pressure by hot syngas;
- Hot syngas is generated by gasification of the dried coal;
- Hot syngas is cooled by the drying of the coal; and
- Cooled syngas is filtered and conditioned, suitable for combustion in the gas turbines.

A gasifier differs from a combustor in that the amount of air or oxygen available inside the gasifier is carefully controlled so that a relatively small portion of the fuel burns completely. This "partial oxidation" process provides heat. Rather than burning, most of the coal is chemically broken apart by the gasifier's heat and pressure, setting into motion chemical reactions that produce "syngas". This syngas is primarily hydrogen, carbon monoxide and other gaseous constituents; the composition of which depends upon the conditions in the gasifier and the type of coal used.

Minerals in coal separate and remain at the bottom of the gasifier. Sulfur impurities in coal are partially captured and removed by the ash, with the rest converted to hydrogen sulphide and carbonyl sulphide, which forms SO_2 upon combustion in the gas turbine. Nitrogen oxides, another potential pollutant, are not formed in the oxygen-deficient environmental of the gasifier; instead, ammonia is created by nitrogen-hydrogen reactions. The ammonia is stripped out of the gas stream prior to combustion, forming ammonium chloride and ammonium sulphate which are crystallised for disposal / sale.

5.1.3. Combined Cycle Power Plant – Power Generation

The primary fuel used for power generation will be synthesis gas ('syngas') generated from brown coal, and natural gas is expected to be used as start-up fuel, as well as a supplementary fuel. The Gas Turbines generate power from the combustion of syngas, natural gas, or a combination of both gases. The syngas is cleaned of its ammonia and particulate matter and is burned as fuel in a combustion turbine, much like natural gas is burned in a turbine. Additional power is capable of being generated by steam turbines, powered by steam raised by:

- Combustion of exhaust gases (from gas turbines) in the Heat Recovery Steam Generator, with supplementary heat input from natural gas firing; and
- Combustion of char and ash residues from the Integrated Drying and Gasification Plant.

IDGCC technology plants can be configured to facilitate CO_2 capture. The syngas is quenched and cleaned, and then 'shifted' using steam to convert CO to CO_2. The CO_2 is then separated for possible long-term sequestration. The DGDP will consider the potential retro-fitting of this CO_2 capture technology once it is commercially viable.

It is expected that the Dual Gas Combined Cycle Power Plant will operate at 95% availability. During Stage 1 operations (i.e. 1 only Integrated Drying and Gasification Plant), it is expected to be fuelled by syngas (about 42%) and by natural gas (up to 53%). The completed demonstration power station, (i.e. after the construction of the second Integrated Drying and Gasification Plant), is expected to be fuelled by syngas, (about 85% of the time), and by natural gas, (up to 10%), with 5% downtime. The amount of time that the plant runs on each gas will be influenced by the spot price of electricity, the availability and cost and contract supply terms of coal and natural gas, the greenhouse emission intensity of each mode of operation and the cost of carbon permits.

Approximately 510 MW of the completed proposed demonstration power station output will be operated as a base-load demonstration power station. An additional approximate 90 MW will be operated as an intermediate or peaking load plant, through additional output from the steam turbine achieved by firing the HRSG with additional natural gas (refer to Figure 5). Thus there will be approximately 600 MW of power in the combined cycle power plant to be sent out to the 500kV transmission grid for sale in the National Electricity Market (NEM).

5.1.4. Environmental controls

The Table below presents the key processes and associated environmental controls involved in the IDGCC process.

Key process steps	Key inputs	Key outputs	Key environmental controls
Integrated Drying and Gasification Plant	• Brown Coal • Energy	• Char • Ash • Clean syngas	• Contained system • Monitoring and process control systems
Combustion of Char	• Char	• Steam	• Bag filters • Monitoring and process control systems
Combined Cycle Power Plant	• Clean syngas • Steam • Natural Gas • Water	• Electricity	• Steam injectors (for NO_x control) • Ammonia scrubbers • Stack heights & velocities to ensure compliance • Monitoring & process control systems

5.1.5. Reliability of Proposed Technology

The reliability of the DGDP plant is expected to be maintained at 95%, allowing 5% downtime for forced shut-down and will consist of the following operational structures:

- Combined cycle block operating at 95% reliability at all times
- Initially, the Gasification system will operate for 40% of the allocated available time, ramping up to a total of 85%
- The DGDP plant will be available to run on natural gas when the gasification system is unavailable and thus maintain 95% reliability

Integrated Gasification Combined Cycle systems which operate using high rank coals have been operational since the mid 1990's at demonstration plants running at between 250-300 MW (Phillips, 2005). Various forms of technology were utilised in these earlier designs, where availability of the systems of approximately 70% were obtained after 9 years of operation. Advances in availability were primarily due to improvements in ancillary equipment. Therefore, a final availability of 85% for the IDGCC technology is deemed achievable considering similar technology utilised in IGCC plants in Italy are achieving between 80-90% after 2-3 years of operation (Collodi & Brkic, 2003) and based on experiences learnt operating the 10MW IDGCC CGDF plant at Morwell.

Natural Gas fired combined cycle power plants are a well established technology where recent statistics quoted by Strategic Power Systems indicate reliabilities of about 98%. Considering access to natural gas, coal resources and grid connectivity is expected to be very high and noted as meeting >95% availability in all cases, an overall reliability of 95% is expected to be very achievable and leaves a few percentage points as a suitable contingency.

Non-success of the gasification plant will result in the plant being converted into a natural gas fired combined cycle plant.

5.2. Environmental best practice

Dual Gas Pty Ltd is committed to demonstrate at commercial scale a technology and project that achieves environmental best practice.

The DGDP will assist in meeting the requirement for base load power generation utilising a technology that is expected to deliver a significantly (about 30%) lower CO_2 intensity than current Latrobe Valley brown coal fuelled power stations. This is consistent with the objectives of the Australian Government's proposed CPRS and Victorian governments Green Paper on Climate Change.

The introduction of the Commonwealth Government's proposed CPRS is likely to have a negative impact on the electricity supply-demand balance within Victoria. Modelling of NEM operation

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under the CPRS by Treasury (Commonwealth of Australia, 2008) anticipates potential market share loses for existing brown coal-fired power stations – requiring the development of new power generation capacity. This will need to be replaced by a mix of renewable power generation (e.g. wind, geothermal, solar, biomass), thermal power generation sources (e.g. natural gas, high efficiency coal-fired plant) and/or strengthened transmission interconnections with other States.

Best practice is defined as 'the best combination of techniques, methods, processes or technology used in an industry sector or activity that demonstrably minimises the environmental impact of that industry sector or activity' in the EPA Works Approval Guidelines, Publication 1307.2. The following sections demonstrate how the selection of various processes and technologies has been made with the aim of demonstrating best practice in the use of brown coal as a source of power.

Applying the IDGCC technology, the DGDP is expected to have an average GHG emission intensity in the range of 0.78 to 0.89 tonne CO_2-e/MWh, lower than the current best performing brown coal power station in Victoria (Loy Yang A; *i.e.*, 1.21 tonne CO_2-e/MWh), and close to or lower than current black coal power station performance with an intensity range of approximately 0.85 to 1.06 tonne CO_2-e/MWh.

Under the operation of the National Electricity Market (NEM) with a price on carbon, power from the Dual Gas Demonstration Project is anticipated to competitively displace power generation from other base-load power stations with higher greenhouse intensity. Overall, this can be expected to lower GHG emissions per MWh of electrical energy sent out associated with power generation in Victoria, while efficiently utilising the State's abundant resources of brown coal.

Efficiency is expected to range between 35% to 37% Higher Heating Value (HHV) - dependent upon the coal source - compared with the current best practice efficiency for Latrobe Valley brown coal fuelled plant of about 29% HHV. This increases the efficiency of power generation by up to approximately 30% compared to current best practice Latrobe Valley brown coal fuelled power station in operation.

5.2.1. Coal Drying and Gasification Process

The coal drying and gasification processes convert the solid brown coal into a gaseous fuel, enabling the use of efficient gas turbine technology for power generation.

The integration of the coal drying with the gasification process provides several benefits:

- The majority of the solid fuel handling is based on high moisture content fuel, with dried coal only handled within the (fully enclosed) pressurised system immediately before use;
- Integration of the drying and gasification simplifies the process, avoiding costs and operational issues associated with separate coal drying and syngas cooling plants;

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- Evaporating moisture from the coal at pressure increases the mass flow of syngas to the gas turbine plant, contributing to the output of the gas turbine plant; and
- The presence of steam in the syngas moderates combustion temperatures (assisting in the control of NO_X emissions[††]).

The coal drying and gasification plant is better suited to operation at steady conditions rather than fluctuating throughput. Operation of the plant to provide base load power will result in a higher efficiency combined cycle plant, compared with an open cycle gas turbine plant (with intermittent fuel supply).

5.2.2. Application of Combined Cycle System

The proposed demonstration power station applies a combined cycle system in which heat energy in hot exhaust fumes from the GTs is recovered and used to generate steam in HRSGs and then the steam is used to power a STG to generate additional electricity. This increases the efficiency of power generation by up to approximately 30% compared to current best practice Latrobe Valley brown coal fuelled power station operation.

The proposed demonstration IDGCC plant will use two E-class gas turbines with proven and guaranteed performance with low calorific value syngas (i.e. minimal risk associated with the combined cycle power plant performance).

5.2.3. Air Cooled Condenser

The DGDP will utilise Air Cooled Condenser (ACC) technology rather than a Wet Cooling System as the primary cooling technology for cooling condensate in the steam cycle. Although this will slightly lower the plant's performance during periods of high ambient temperatures and also increase the capital cost, it minimises water consumption. A comparison of the two systems is provided in Section 5.3.2.

As detailed in Section 4.2.3 the DGDP is expected to use about 75% less water per MWh than the existing best practice brown coal fired power station in the Latrobe Valley. Of this amount, about 35% is attributed to the ACC technology.

5.2.4. Water Reuse and Recycling System

Some of the water obtained from the raw brown coal in the coal drying process, remains as part of the syngas to add mass to the gas turbine flow, thus increasing power output. Some water is extracted from the syngas as part of the syngas cooling and clean-up step. Heat exchangers are used to cool the syngas below the dew point to remove this water, prior to the syngas entering the

[††] Thermal NO_X can be formed by oxidation of N_2 (present in the combustion air) at high temperatures.

ammonia scrubber. Water extraction is required to ensure that the heating value of the syngas supplied to the gas turbine is above the lower limit set by the gas turbine supplier. The quantity of water extracted will be dependent on the gas quality produced by the gasifier and the quantity of natural gas mixed with the syngas to increase the gas heating value. The water from the syngas (following clean-up) will be used in the auxiliary cooling system and is expected to reduce the make-up water requirement.

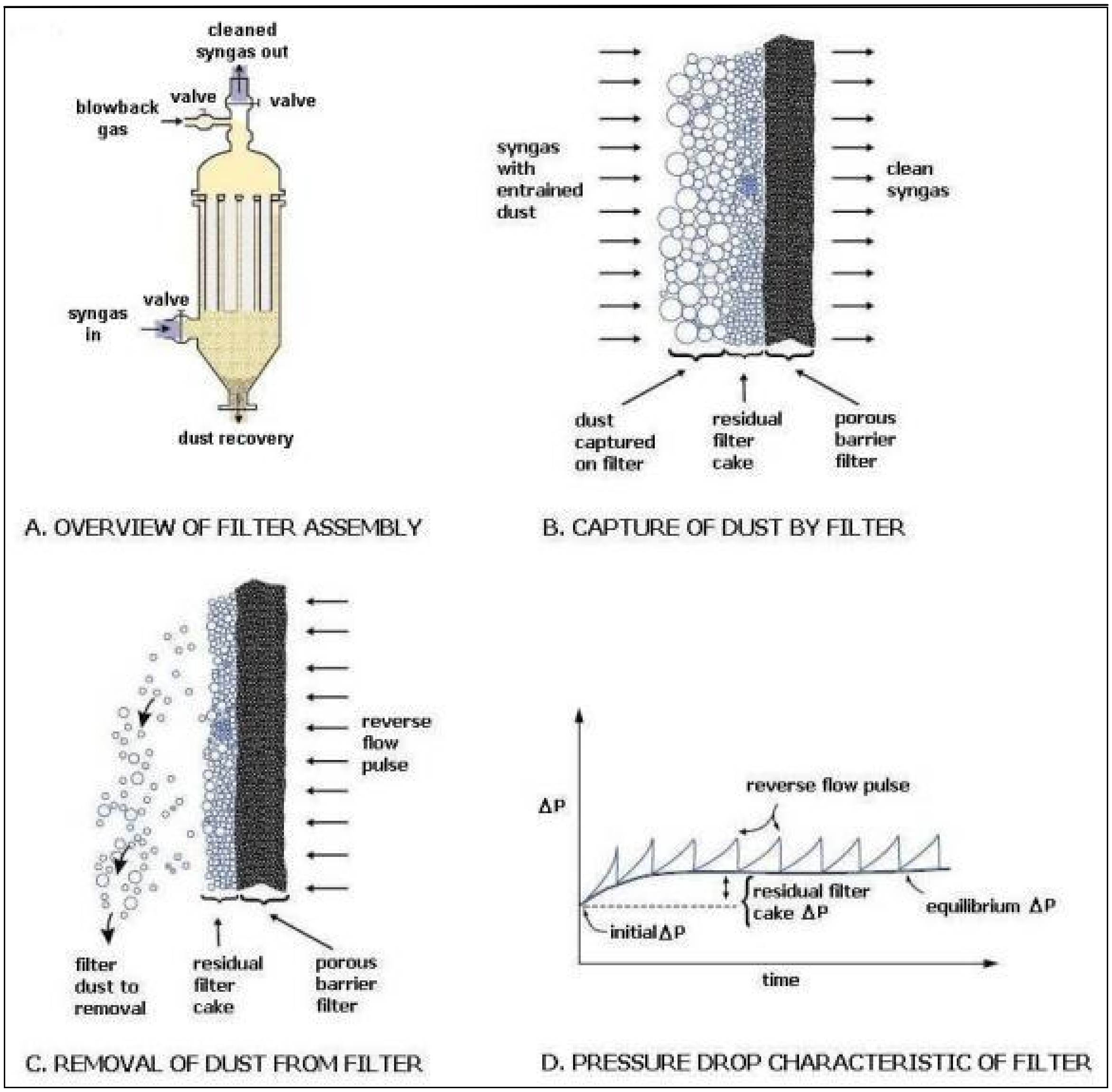
Modelling has shown that a maximum of 50 tph of water could be extracted from the syngas. It is expected though that an average quantity of approximately 20 tph will be extracted (which is the basis of the water balance provided in Section B1. Note that the efficiency of the Dual Gas Demonstration Plant is maximised at minimal water extraction.

Saline wastewater discharged from the ash sluice system into the Hazelwood Ash Pond will be recycled, after ash and other particles are settled at the bottom of the pond, and returned to the proposed demonstration power station to be reused in the closed ash disposal transport system.

5.2.5. Ash Filtration Systems

Syngas Cleaning System

The filtration technology employed is a porous ceramic in the form of a hollow candle. Dust is collected on a fine outer layer, whilst the clean syngas passes through. Dust is removed from the candle by reverse flow pulsing – see Figure 9.



- **Figure 9: Syngas cleaning system**

Efficient removal of particulates from the syngas is essential to avoid damage to the gas turbine. As a result, emissions of particulates to the atmosphere from the combined cycle plant are expected to be negligible compared to current coal fired Latrobe Valley power stations.

Flue Gas Cleaning System – Char Combustion

Char and ash collected from the particulate filtration system and from the gasifier hopper are proposed to be burnt in a boiler to raise steam.

The ash from this combustion will be essentially identical to the ash from other Latrobe Valley power stations. This ash will be collected by bag filter technology.

The efficiency of bag filtration is higher than that of electrostatic precipitators (as used on other Latrobe Valley boilers). Bag filters are not used on conventional Latrobe Valley Power stations due to the high gas flow associated with combustion of the high moisture content brown coal.

Ash Filtration Efficiencies

It is expected that ash separation efficiencies of greater than 99% will be achieved for both the syngas cleaning (using candle filters) and char burner flue gas cleaning (using bag filters). Separation efficiencies of > 99.9% are achievable with the candle filter technology. A back-up filter shall also be employed to provide additional protection for the gas turbines (and hence to reduce particulate emissions) should there be any failure of any of the candles within the main filter. Modern, high separation efficiency filter bag technology will be used for separation of particulates from the char burner stack. The bag filters are to be specified to achieve a total particulate concentration in the stack of 50 mg/m3 (dry / 7% O_2), which equates to a separation efficiency of about 99.8%.

5.3. Integrated environmental assessment

The DGDP design put forward in this Works Approval is the development described in Section 5.1. The decision process to come to this selected development includes a number of considerations encompassing environmental impacts, economic feasibility, regulatory compliance and local amenity.

As detailed in Section 4.2, the DGDP provides a significant reduction in greenhouse gas emissions and water usage per unit of electricity generated compared to other brown coal power stations in the Latrobe Valley, Victoria.

Modelling of air emissions assuming various stack heights had minimal impact on overall SO_2 and NO_2 and PM_{10} levels. These were all predicted to be below the State Environment Protection Policy 1-hour Design Ground Level Concentration (DGLC) of 0.10ppm, 0.17ppm and 0.08 mg m^{-3} respectively.

Similarly, the DGDP provides a significant reduction in water consumption, partly due to the selection of an Air Cooled Condenser system compared with a Wet Cooling system.

In making a determination on the stack heights and Air Cooling vs. Wet Cooling the following aspects were considered:

- Compliance with State Environment Protection Policy (Air Quality Management)
- Air emissions
- Resource efficiency
- Water usage
- Visual amenity
- Site constraints
- Financial implications

These are detailed in the following sub-sections.

5.3.1. Stack Height

The height of the combined cycle power plant stacks (and other stacks including Air Heater, Char Burner and Coal Pre-Dryer) are approximately 80m and this is what the air quality modelling has been based on.

5.3.1.1. Air Emissions

The final stack heights will be determined over the coming months following detailed discussions with the EPC contractor and are expected to be approximately 80m in height.

5.3.1.2. Economic Viability

The financial implications of different stack heights are that the higher the tower, the higher the capital cost.

5.3.1.3. Visual Amenity

As described in Section 2.1.2, the site is located in an industrial zone of the Latrobe Valley, has immediate neighbours on the north and east sides of the site's boundaries and is 1.3 km from the nearest residential area. The industrial location is not a visually sensitive area in comparison to the residential location, and the proposal has been assessed as not representing a significant visual impact. However, proximity to neighbours and direct visibility of the stack from the precincts main access roads suggests that a higher stack height may lead to a more visually imposing development.

Avoidance of a wet cooling system eliminates the visual impacts associated with wet cooling tower plumes.

5.3.1.4. Conclusion

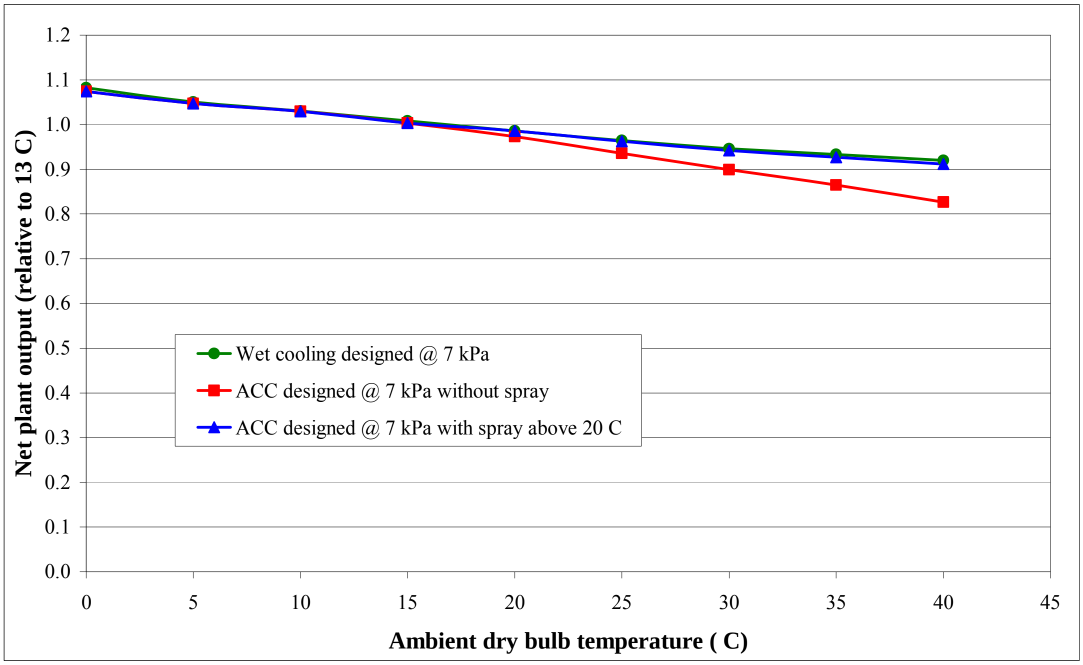
The design considerations indicate that the stack heights investigated are both acceptable alternatives. These stack heights achieve NO_x and SO_2 and PM_{10} ground level concentrations well within the levels required by SEPP (AQM), maximises the reduction to emissions intensity, and considers visual amenity of the surrounding area. The discussion also shows that the higher the tower, the higher the capital cost.

5.3.2. Air Cooled Condensers

The use of air cooled condensers saves approximately 2.8 GL of water per annum compared to using a traditional wet cooling system. This comes at a higher capital cost (about $10 M) and slightly lower output during high ambient temperatures (when electricity demand is at its maximum). On a 40°C day this is estimated to be <5 MW (i.e. <1% of total output), assuming the use of water sprays with the ACC.

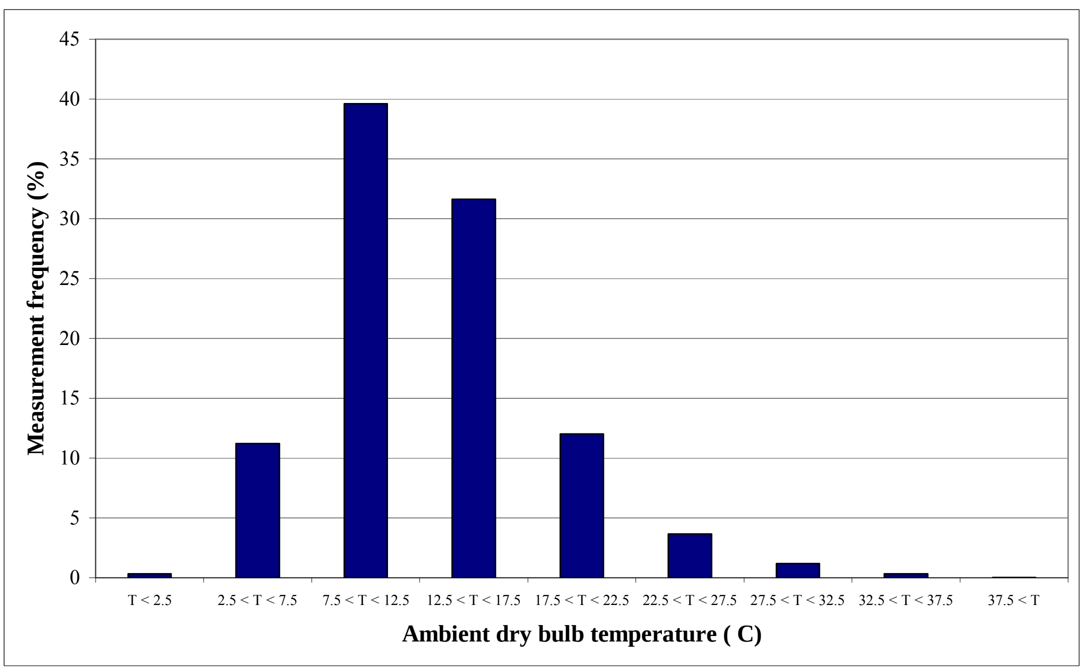
Studies have been conducted to compare the performance of wet vs dry cooling and water consumption on plant efficiency for the DGDP. The net plant output for wet cooling (i.e. cooling tower) has been compared with two air cooled condenser (ACCs) cases - with and without water sprays. Water sprays are often used with ACCs to increase cooling during hotter days, allowing the condenser to operate at lower pressure, which acts to increase efficiency and power output.

Figure 10 shows that for ambient temperatures for both Wet and Dry Cooling. Below about 20°C there is almost no difference in the net plant output for wet or dry cooling. Above 20°C there is degradation in ACC performance, resulting in lower plant efficiency and net plant output. The degradation in performance increases with increasing ambient temperature.



- **Figure 10: Comparative Net Plant Output for Wet and Dry Cooling**

However, it should be noted that only just above 5% of the time is the ambient temperature above 22.5°C in the Latrobe Valley (see Figure 11). For periods of high ambient temperatures, modelling has shown (see Figure 10) that the use of water sprays can return the net output of the plant very close to that for wet cooled condensers.



- **Figure 11: Ambient Temperature Distribution in the Latrobe Valley**

The choice of whether to install water sprays in the ACC shall be taken as part of the Front End Engineering Design (FEED), based on its technical and economic merits. The use of water sprays (used for ambient temperatures above 20°C) would result in an annual average water consumption of about 0.1 ML/MWh, compared with about 0.9 ML/MWh with wet cooling.

It can therefore be concluded that given the substantial water savings and relatively minor effect on plant efficiency or output, that the use of air cooled condensers for the DGDP is particularly appropriate for the Latrobe Valley conditions.

5.4. Choice of process and technology

The IDGCC technology is a process that combines the pressurised drying and gasification of brown coal with gas turbine combined cycle power generation. IDGCC technology is expected to enable power to be generated from brown coal with reduced CO_2 emissions intensity and water usage compared to existing Latrobe Valley brown coal fired power generation technology.

This technology has been developed over a period of more than 20 years, initially prompted by the Victorian Government Natural Resources & Environment Committee inquiry (1985-88) into Electricity Supply & Demand Beyond the Mid-1990s. The IDGCC technology development pathway has included:

1) Process and economic modelling and laboratory-scale testing
2) The development and operation of a 0.5MW Coal Gasification Demonstration Unit (CGDU) at Mulgrave, in the south-eastern suburbs of Melbourne. Initially the CGDU demonstrated the gasification of a range of coals. In more recent times it has been operated to supply a syngas stream for pre-combustion carbon capture trials.
3) The development and operation of a 10MW Coal Gasification Development Facility (CGDF) near Morwell in the 1990s in Latrobe Valley. The CGDF successfully demonstrated the IDGCC process from coal preparation through to syngas combustion in a grid-connected 5MW gas turbine and Heat Recovery Steam Generator.

The proposed development is the fourth stage of the IDGCC technology development pathway and aims to demonstrate the IDGCC technology at commercial-scale.

If this fourth stage is successful, the fifth technology development stage is expected to be the combining of the IDGCC technology with carbon capture (CC). On 20 January 2010, the State Government announced “Cleaner Energy Projects Share in up to $29 Million” [4]. This announced that HRL will be provided with a grant of up to $3.5 million to investigate the feasibility of a pre-combustion CO_2 capture project.

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The DGDP is to use E Class turbines, which have a proven track record with the use of syngas. As the provider of the IDGCC technology, HRL is also working with gas turbine suppliers to allow the use of syngas with the more efficient F class turbines in the future, which is expected to result in about a further 12% gain in efficiency.

The IDGCC technology has the potential to improve the efficiency of resource use (coal and water) in power generation compared to existing coal fired power generation in the Latrobe Valley.

The following table presents each process option considered and the factors that were considered in the selection process.

Process/ Technology	Advantages	Disadvantages
Gasification Process		
Air-blown gasification	Suitable for reactive brown coal, such as coals from the Latrobe Valley.	Larger gasifier and heat exchanger size required = increased cost.
Oxygen-blown gasification	Higher energy content syngas. Assists in carbon capture by increasing the concentration of CO_2 in the syngas stream.	Significantly decreases the efficiency of power generation and increases costs. Considered unnecessary for the reactive brown coals in the Latrobe Valley.
Condensate Cooling		
Wet Cooling System	Greater cooling efficiency, especially during high ambient air temperature.	High water consumption in a water constrained environment.
Air Cooled Condenser (ACC) technology	A further 20% reduction in water usage per MWh is expected.	Slightly lowers the plant performance during periods of high ambient temperature. Higher capital cost.
Pre-Combustion Carbon Capture		
Pre combustion CO_2 capture	CO_2 emissions intensity of the demonstration power station could be expected to be lower than the CO_2 emissions intensity of current natural gas combined-cycle power stations. Already available and has been widely used in oil/gas and associated process industries.	Transport and storage of CO_2 is not yet commercially or technically viable. Less efficient and uneconomic.

Dual Gas will undertake a hazard and operability study (HAZOP) of the proposed processes and technology as part of the design process in order to ensure the plant is operated safely.

5.5. Choice of location and layout

5.5.1. Site Location

Alternative locations adjacent to existing open cut mines in the Latrobe Valley were considered. Dual Gas Pty Ltd has been able to secure the proposed site under suitable commercial conditions for the development of the Dual Gas Demonstration Project. The proposed site for the demonstration power station also has advantages compared to alternative sites considered as detailed below.

Location or layout	Advantages
Commercial Road, Morwell, Latrobe Valley	• More effective utilisation of existing facilities, such as for coal supply, ash disposal, water supply and car parking, thus able to minimise the construction footprint. • This project will require only minor amendments to the existing infrastructure on the existing site for water supply, coal supply and waste disposal, thus is able to avoid any significant impacts on native vegetation and other natural resources. • The site is already a disturbed industrial site, thus minimising the need to remove remnant native vegetation. • The Dual Gas demonstration power station site is predominantly located within the Special Use Zone 1 of the Latrobe Planning Scheme which is designated for brown coal mining and electricity generation and associated uses. The project site is a highly disturbed industrial site currently used for car parking and briquette storage purposes. • Relatively close proximity to the existing grid connection point. • The project site will also allow for relatively easy access (approximately 4 km southeast from the site) to Hazelwood Terminal Station and then to the existing 500kV transmission lines through which the generated power is expected to be distributed across Victoria and the National Electricity Market.

5.5.2. Description of selected site

A full description of the site is presented in Section 2.1.2.

The proposed Dual Gas Demonstration Project site is located approximately one kilometre south of the Morwell township, which is approximately 150 km southeast of Melbourne’s Central Business District. The site is located on an existing open- air briquette storage area and car park within the Energy Brix Australia Corporation (EBAC) site at Commercial Road, Morwell, as shown in Figure 2.

The EBAC site is bounded to the west by Monash Way and to the north by Commercial Road. The proposed demonstration power station site has been highly disturbed and is sparsely vegetated and limited to lawn, grasses and scattered mature trees located on access road verges and the edge of the existing car parking area. Most of the subject site has been used as a briquette storage area for the past 50 years and is covered in dry coal. The western end of the site has been partially excavated to create a hardstand car park.

5.5.3. Key layout alternatives currently under investigation

5.5.3.1. Plant configuration

The following arrangement of plant will be further examined to optimise performance and to ensure regulatory compliance:

- Stack height for combined cycle plant
- Noise mitigation measures as specified in Appendix E

5.5.3.2. Transmission Line Route

Two route options have been considered and assessed to date. The final alignment is expected to be determined by consideration of the following aspects:

- Technical feasibility
- Number and nature of affected landowners, and
- Potential environmental constraints.

The two possible routes already have many existing electricity transmission lines. Desktop investigations have determined that there are no environmentally significant areas along both routes. Dual Gas is committed to ensure that the transmission pylons are located to avoid or minimise any significant impact on environmentally sensitive areas (if identified through further detailed assessment).

5.5.3.3. Coal Transport Route

If coal is sourced from Yallourn North Extension coal field at some point in the future, the coal supply route to the proposed demonstration power station site will be finalised to minimise the community impact (e.g. noise and traffic) of this coal transportation. A study has been conducted to assess the significance of potential impacts on the surrounding communities and the durability and capacity of the existing road infrastructure to accommodate additional traffic associated with the coal transport. The results conclude that the eastern route – via Maryvale Rd – would have the least impact on the community from a noise and traffic perspective. Should the Yallourn North Extension coal field option proceed, Dual Gas will undertake a separate consultation process.

6. RESOURCES

6.1. Carbon

The overall level of energy use for the DGDP is estimated to range between 37.4 to 40.0 PJ/yr (Cases 1-3, syngas + natural gas) and over the life of the project the average greenhouse gas emissions intensity (Scope 1) is expected to range between 0.73 to 0.78 tonnes CO_2-e/MWh. Further energy and greenhouse gas emissions data is presented in Section A1 and the full greenhouse gas assessment is provided in Appendix D.

The greenhouse gas intensity for the DGDP is significantly lower than other Latrobe Valley brown-coal fired power stations, as shown in the table below.

Plant	Greenhouse Gas Intensity (tonne CO_2-e/MWh Sent Out)	Estimated Electricity Used Internally	Greenhouse Gas Intensity (tonne CO_2-e/MWh as generated)
Hazelwood (Vic)[‡‡]	1.52	8%	1.40
Yallourn (Vic) [§§]	1.42	8%	1.31
Loy Yang B (Vic) [***]	1.23	7%	1.14
Loy Yang A (Vic) [†††]	1.21	7%	1.12

Mass and energy balance calculations have been conducted on the two key operating scenarios described as follows:

- **Case 1** – two gas turbines operating on syngas from Morwell coal, running 100% output with full duct firing on natural gas.
- **Case 2** – two gas turbines operating on natural gas, running 100% output with Full duct firing on natural gas.

A summary of the energy balance results is shown in Figure 12 and Figure 13. The mass balances for these two cases are provided in Figure 7 and Figure 8.

[‡‡] International Power Hazelwood, 2006. *Social and Environment Report 2006*

[§§] TRUenergy, 2009. *Social and Environmental Snapshot*.

[***] International Power Australia, 2006. *Loy Yang B Power Station Environmental Performance Report 2006.*

[†††] Loy Yang Power, 2007. *Sustainability Report 2008.*

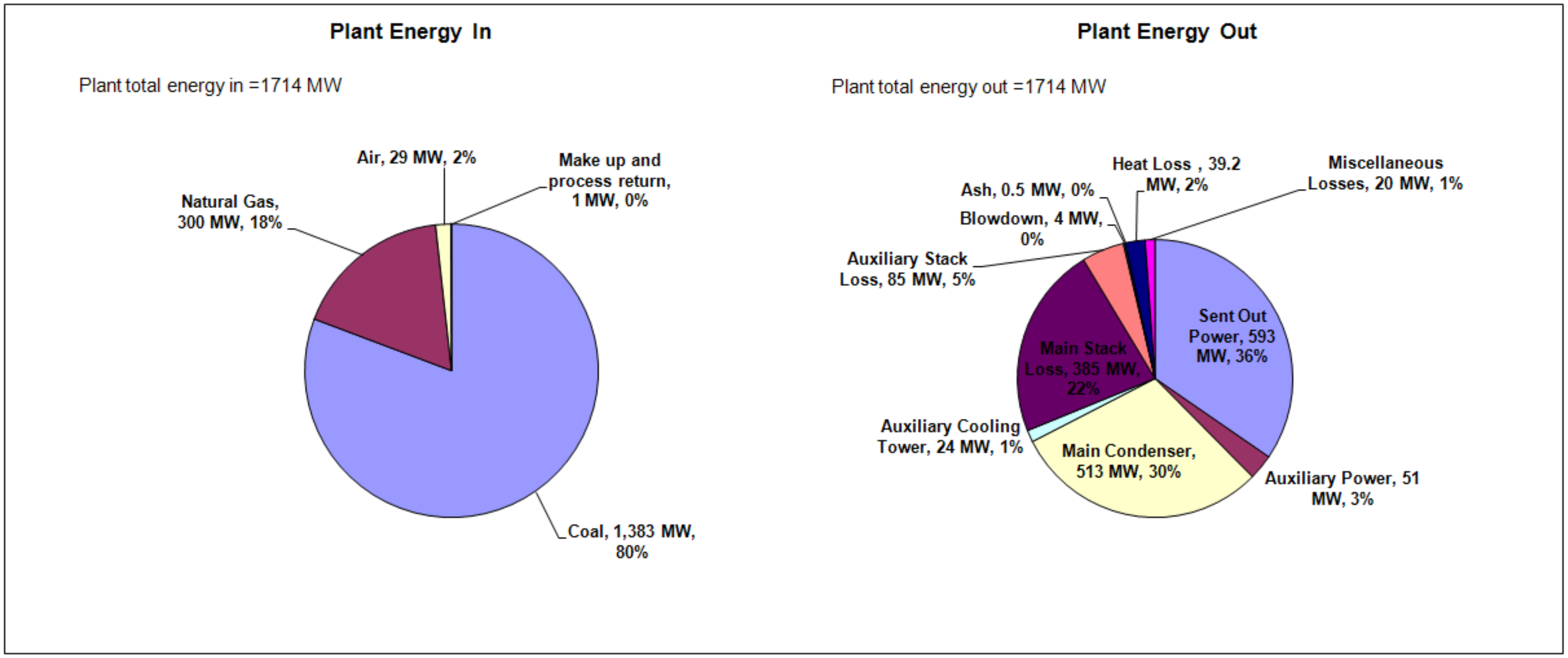
The key plant components for energy inputs and outputs are as follows:

Energy Inputs:

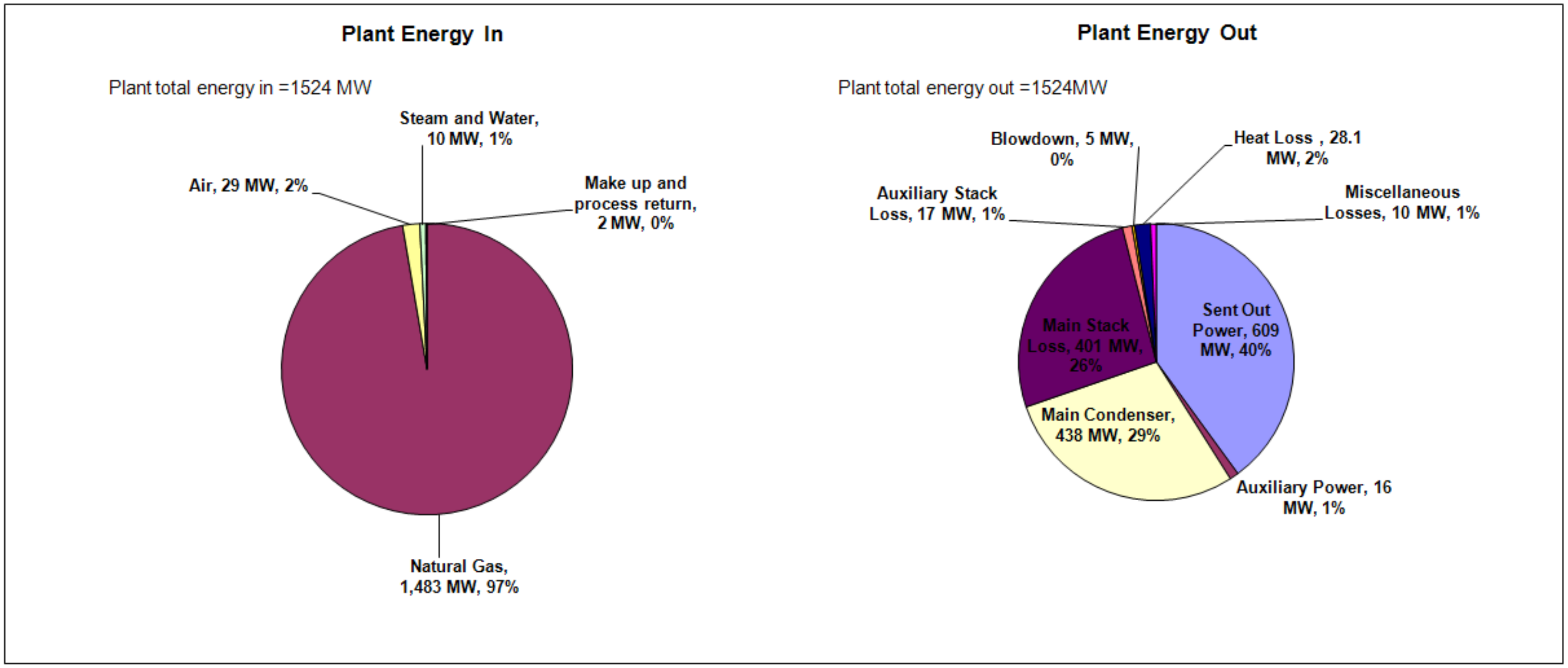
- Coal
- Natural Gas
- Air
- Steam and Water
- Make up and process return

Energy Outputs:

- Sent Out Power
- Auxiliary Power
- Main Condenser
- Auxiliary Cooling Tower
- Main Stack Loss
- Auxiliary Stack Loss
- Blowdown
- Ash
- Heat Loss
- Miscellaneous Losses



- **Figure 12: Energy Balance (Case 1 – two gas turbines operating on syngas from Morwell coal, running 100% output with full duct firing on natural gas).**



- **Figure 13: Energy Balance (Case 2 - two gas turbines operating on natural gas, running 100% output with full duct firing on natural gas).**

6.2. Water use

Up to 2 GL/yr is expected to be required during operation of the proposed DGDP. Following discussions with DSE and DTF, Dual Gas has been provisionally provided a 2GL/yr water allocation from Blue Rock Dam at 95% reliability. A reliable yield of 95% corresponds to Gippsland Water's level of service commitment to their urban customers in the Latrobe Valley (Gippsland Water, 2007).

Further information on water use is provided in Section B of this document.

6.3. Solid waste

No significant solid waste will be produced on-site by the Dual Gas Demonstration Project. Solid wastes will be limited to:

- **Ammonium chloride and ammonium sulphate**: Ammonium sulphate is used as a fertiliser and Ammonium chloride is used as a feedstock in the galvanising industry. These by-products are expected to be recovered by concentration and crystallisation and expected to be on-sold;
- **Ash:** The ash discharged from the Project will be indistinguishable to the ash from a conventional brown coal fired power station in the Latrobe Valley. When the Dual Gas Demonstration Project is using coal from the mine adjacent to the proposed demonstration power station site water from the ash pond will be used to transport this ash for disposal into the ash pond. The disposal of the settled ash at the bottom of the pond is expected to be managed by International Power Hazelwood who will manage the storage of this ash;
- **General Waste:** Putrecible and organic (food waste), recyclables, including glass, plastics, aluminium, paper, cardboard, scrap metals and wood;
- **Hazardous Wastes:** Minor quantities including chemicals, solvents, paints, resins and materials from clean-up of chemical spills (eg absorbent materials).

All other wastes are expected to be minimal (e.g. general wastes, recyclables) and will be contained on-site and stored in segregated areas. These wastes will be removed from site and recycled or disposed of by a licensed contractor as required. Refer to Section C for further details on solid waste.

6.4. Prescribed industrial waste

Prescribed industrial waste produced on-site by the Dual Gas Demonstration Project will include:

- **Fly ash** (40,000 tonnes per annum): - waste management described in the section above, to be handled in a manner consistent with normal power station practise in the Latrobe Valley;
- **Hazardous Wastes:** Minor quantities including chemicals, solvents, paints, resins and materials from clean-up of chemical spills (eg absorbent materials). The quantity of spent ion exchange resin consumed will depend upon a range of factors including raw water quality, quantity of water extracted from the process and quantity of water consumed by the process.

The *Environment Protection (Waste Resource) Regulation 2009* and its corresponding IWRGs will be adhered to for disposal of any potential wastes identified as Prescribed Wastes under these Regulations (eg ion exchange resins). For the hazardous wastes listed above, this shall include containment on-site and storage in segregated areas. These wastes will be removed from site and recycled or disposed of by a licensed contractor as required.

Refer to Section C for further details on solid waste.

7. EMISSIONS

7.1. Air emissions

This section reports DGDP's key (SEPP-AQM Class 1) emissions of airborne substances with respect to potential effects on ambient air quality. For greenhouse gas emissions, see Section 4.2.1. Further details on the DGDP's air emissions are provided in Section E, in accordance with Section 7 of the Works Approval Guidelines.

7.1.1. Air emission rates for the dual gas-fuelled DGDP operation

With respect to potential effects on the ambient air environment, the key airborne substances emitted by the syngas-fuelled DGDP are detailed in the table below; *i.e.*, not including emissions of harmless gases such as nitrogen, oxygen, and water vapour (as well as the greenhouse gas CO_2). For completeness, emission rates are provided for NO also (with NO_2 being the Class 1 indicator and NO_x comprising NO and NO_2). These estimates are based on 100% output by two syngas-fuelled gas turbines with maximum duct firing on natural gas.

Emission Type	Total Emission Rate (g/min)	Substance Class (SEPP-AQM)	Reason for Classification (SEPP-AQM)
Gas (SO_2)	24,480	Class 1	Toxicity
Gas (NO)	5,340	Nil	NA
Gas (NO_2)	300	Class 1	Toxicity
Gas (CO)	1,080	Class 1	Toxicity
Particles (as PM_{10})	1,080	Class 1	Toxicity

Source: HRL (2010a); and the associated HRL spreadsheet, '*emissions values.xls*'.

Hazardous substances that may threaten the air environment due to their toxicity, bio-accumulation or odorous characteristics are the SEPP-AQM Class 2 indicators. No significant emissions of Class 2 substances are expected from the syngas-fuelled DGDP.

The Victorian SEPP-AQM Class 3 indicators include very harmful airborne substances such as beryllium, dioxins and furans, and Respirable Crystalline Silica. A detailed study of potential emissions of Class 3 indicators by the proposed DGDP undertaken by HRL (2010b) shows that such emissions are expected to be negligible.

7.1.2. Air emission rates for the natural gas-fuelled DGDP operation

The key airborne substances emitted by the natural gas-fuelled DGDP are detailed in the table below, not including emissions of harmless gases. These estimates are based on 100% output by two natural gas-fuelled gas turbines with maximum duct firing on natural gas.

Emission Type	Total Emission Rate (g/min)	Substance Class (SEPP-AQM)	Reason for Classification (SEPP-AQM)
Gas (SO_2)	0	Class 1	Toxicity
Gas (NO)	3,420	Nil	NA
Gas (NO_2)	180	Class 1	Toxicity
Gas (CO)	780	Class 1	Toxicity
Particles (as PM_{10})	660	Class 1	Toxicity

Source: HRL (2010); and the associated HRL spreadsheet, '*emissions values.xls*'.

No significant emissions of SEPP-AQM Class 2 substances are expected from the natural gas-fuelled DGDP. Emissions of Class 3 indicators from a natural gas-fuelled DGDP are expected to be negligible (see also the discussion on Class 3 indicators in the previous section for syngas).

7.1.3. Conclusion

With respect to potential air quality effects in the Latrobe Valley, the DGDP emissions of the key air pollutants SO_2 and NO_2 will be controlled as far as practicable and in the ambient air environment, modelling in accordance with the SEPP-AQM indicates that the predicted Ground Level Concentrations will be below relevant design criteria.

Particulate matter emissions are expected to be very low and controlled by high efficiency barrier filters.

7.2. Discharge to surface water

The Dual Gas Demonstration Project will generate waste water of three main natures, including:

- Domestic water from the administration building
- Stormwater runoffs
- Ash sluice water

Bunding shall be used to contain any accidental spillage from acid storage tanks (used for demin plant and ammonia scrubber).

7.2.1. Domestic Water

Waste water from administration building (i.e. showers, toilets, and kitchen) will be discharged to a sewage system.

7.2.2. Stormwater runoff

Waste water and stormwater run-off from the site is currently discharged through a storm water drainage system to a settling pond owned and operated by Energy Brix Australia Corporation (EBAC). Suspended solids and organic particulates settle in the settling pond and are removed prior to discharge into Bennetts Creek. Discharges from the settling pond into Bennetts Creek operate under an EPA discharge licence held by EBAC. Water quality in the settling pond and Bennetts Creek is monitored on a daily basis.

Stormwater run-off from the Dual Gas Demonstration Project is proposed to be discharged through this existing licence to Bennetts Creek via the settling pond. The volume of water discharged to Bennetts Creek is expected to increase slightly due to an increase of impervious areas (e.g. hardstand, buildings and plants) within the site and additional blowdown from the auxiliary boilers. However the capacity of the settling pond is estimated to be sufficient to accommodate the increased discharges and the discharge to Bennetts Creek will be maintained within the existing licence. This is because the land footprint will not change, the blowdown water is negligible (< 0.4GL pa and the increased impervious area will be offset by part removal of car parks. The clean-up of the briquette storage yard will also see less particulates going to the settling pond.

To ensure that contamination risks are minimised, stormwater management procedures for external areas will be put in place. All chemicals used, and wastes generated at the facility will be handled and stored in such a way that pollutant discharges to stormwater are prevented. Process liquid transfer points and process areas that have potential for liquid spillage will be bunded so as to provide spill containment and prevent contaminated run-off.

Please refer to Section I for further information on Environmental Management.

7.2.3. Ash Sluice Water

Water from the ash sluice system is expected to be discharged into the Hazelwood ash pond which is owned and managed by International Power Hazelwood. The supernatant water in the ash pond will be withdrawn and returned to the demonstration power station for reuse in a closed loop system. Excess water in the Hazelwood ash pond will continue to be discharged via the Saline Water Outfall Pipeline system as per existing industry arrangements.

Further information on water discharge is provided in Section F.

7.3. Discharge to land

No water will be discharged to land.

It should be noted that the majority of the ground surface of the site is covered by buildings and concrete and asphalt roadways/path. Appropriate measures will be in place to ensure that no spills of liquid materials can reach the land environment and wastes will be contained until they are disposed off-site. Contamination risks and management measures are detailed in Section I.

7.4. Noise emissions

As identified previously under section 4.2.4 of this report, the DGDP will comprise a number of noise sources, the major sources based on their Sound Power Level output include:

- Two Heat Recovery Steam Generators (HRSG)
- Air Cooled Condenser (ACC) system
- Air Inlet Duct and Filter system

Those noise sources will be operating 24 hours per day and 7 days a week.

The nearest residential receiver is identified at 1.3 km to the North-West of the demonstration power station. Predicted noise emissions from the demonstration power station using modelling techniques have identified that there is potential non compliance at this residential receiver under the applied night criteria of the most current version of the draft State guidelines "Noise From Industry in Regional Victoria (Publication 1316, December 2009)".

Taking into consideration that the current status of the demonstration power station is awaiting commercial application, a number of solutions have been devised to ensure compliance of the system upon approval for construction. Two main solutions have been identified and may include a contribution of either or both in conjunction:

- Additional Sound Power Level data to be collected and analysed upon further development of the demonstration power station design
- Noise mitigation measures applied to one or more of the major noise sources identified

Feasible noise mitigation measures have been identified for all of the major noise sources of the demonstration power station and may include (but are not necessarily limited to) the following:

- Cooling fan blades of the ACC system replaced with a "low noise" type
- Attenuator fitted to the stack of the HRSG

- Air inlet filter attenuator upgraded
- Lagging of air inlet duct
- Enclosure placed around GT Main Transformer

When noise mitigation measures are applied to these components the noise reductions have been calculated and show a total reduction of 5.5 dBA, lowering the total sound power level to the required EPA noise limit criteria. Refer to Section H for further details on Noise Emissions and Section 7 of Appendix E (Noise Assessment Report) for further details on demonstrating how the night period noise criterion can be met at Residence One (46 McLean Street) with noise mitigation applied to the major noise sources.

8. ENVIRONMENTAL MANAGEMENT

8.1. Non-routine operations

A Risk Assessment will be undertaken to identify the significant environmental risks associated with the construction and operation of the DGDP. The significant environmental operational risks related to the project for non-routine events include:

- Fire or explosion
- Uncontrolled gas release
- Firewater runoff
- Uncontrolled hydrocarbons/chemical releases due to failure, malfunction or leaking connections

Section I provides further information about these risks, their associated environmental impacts and proposed management strategies. Through appropriate control measures, the identified risks can be managed to at least a moderate level. In developing management strategies to address identified hazards and risks, the preferred hierarchy of controls will be:

1) Elimination – eliminating toxic substances, hazardous plant or processes that are not necessary for a system to work.
2) Substitution – where hazardous materials/chemical have been identified as a hazard then the preferred option is to replace the material with a less hazardous one.
3) Engineering – the removal of potential hazards by re-engineering the job is a preferred option. This, for example, may involve such actions as re-designing pipework/equipment or reconfiguring a crane.
4) Administrative Controls – the application of administrative controls to hazards may include such actions as limiting the time of exposure, rotating personnel, training/re-training of personnel.
5) Personnel Protective Equipment – the provision of personal protective equipment does not eliminate the hazard, but only shields the individual from it. Such action may have to be coupled with training in the correct use of the equipment.

In addition, a comprehensive and integrated Emergency Response Plan will be prepared to define the reporting and rectification system for any emergency situation that may occur. This procedure will apply to all Project personnel and contractors engaged in related activities at the Project work site.

8.2. Separation distances

EPA provides recommended buffer distances in EPA publication *AQ2-86 Recommended Buffer Distances for Industrial Residual Air Emissions*. The buffer distance applicable for the Dual Gas Demonstration project area is 1,000 metres.

The Dual Gas Demonstration Project site being located 1.3 km from the nearest residential area (Morwell) and therefore complies with this requirement.

8.3. Management system

HRL recognises the need for effective environmental management and this will be an important component of all aspects of Dual Gas' operations. Dual Gas is committed to have a strong continuous improvement culture and to develop and implement an integrated management system incorporating quality, environment and safety program management that meet business requirements and conform to Australian and international standards:

- AS/NZS ISO 14001: 2004 - Environmental Management System
- AS/NZA ISO 9001: 2000 - Quality Management System
- AS/NZS 4801:2001 - Occupational Health & Safety Management System

During the construction phase, environmental management risks will be managed by the development and implementation of a Construction Environmental Management Plan (CEMP). To ensure that this site CEMP is effectively implemented, a number of key responsibilities will be assigned to project personnel. In addition, to ensure the effective management of procedures outlined in the CEMP, all persons involved with construction activities will receive training. This training will be designed in two parts, induction training for all personnel and specialised talks for specific issues planned for the construction phased of the project. Also, a clearly defined approach to reporting will ensure a transparent approach to the environmental performance of Dual Gas and its construction contractor and associated subcontractors during the construction process. As such protocols in relation to the following forms of reporting will be defined:

- Monthly reports
- Audits reports
- Community Communication
- Non Conformance and Corrective Actions Report
- Complaints
- Environmental Incident Management Reports

During the operation phase, environmental risks will be managed by the development and implementation of an Environmental Management Plan (EMP). The implementation of this EMP will be coordinated by appropriately qualified staff of Dual Gas Pty Ltd. The EMP will cover roles and responsibilities of the implementation, objectives and targets, management measures and procedures, and monitoring systems in place to ensure environmental performance throughout the life time of the demonstration power station.

Refer to Section I for further details on Environmental Management.

8.4. Construction

It is anticipated that construction of Stage 1 of the project will commence in early 2011 and span a period of approximately 30 months. During this period there will be a need to manage the effects of construction activities on the site on the surrounding and regional environment. Potential risks will include:

- Vegetation Clearance and introduction of weeds on-site
- Water run-off - stormwater
- Spills and accidental releases from chemical transport, storage and handling, and equipment failure prevention
- Importation of fill and construction material
- Fire
- Dust generation
- Waste minimisation/recycling
- Interception of groundwater during foundation excavations
- Material spillage
- Heavy vehicle movements
- Generation of waste water and inappropriate disposal
- Materials storage

A CEMP will be prepared prior to construction phase in order to manage these aspects. This will be prepared taking into account the principles and techniques of the EPA’s Environmental Guidelines for Major Construction Sites (Best Practice Environmental Management Series).

Based on the findings of the Environmental Site Assessment (SKM, August 2009), the following recommendations will be included in the CEMP to be developed prior to construction commencing:

- It is considered likely that asbestos cement pipe will be encountered during the site preparation of the proposed project site. The asbestos is considered to be a potential source of contamination at the site if encountered during the development and not dealt with by an appropriately qualified specialist. On this basis, the AC pipe should be removed/dealt with by a qualified specialist in the event that intrusive construction works are required in this area;
- It is understood that as part of the construction activities for the Project, earthworks including the excavation of soils to a maximum depth of 2 metres below ground level will be required in some areas of the site. It is proposed that the waste soils generated during construction are to be battered in the north of the former ash pond within the EBAC complex (but outside of the proposed project site) and landscaped. Given the long history of industrial land uses at the site and the potential sources of contamination identified at the site, the potential for soil and groundwater contamination exists at the site. A Phase 2 Environmental Site Assessment is therefore recommended to further assess this prior to the earthworks and relocation of soils;
- It is also recommended that the removal and reuse of soils on site are managed through the implementation of a site soil management plan. If soils suspected of being contaminated are encountered during the site construction activities, it is recommended that this material be assessed by sampling and analysis, and the results used to inform a decision on the risks associated with its reuse. If unacceptable for reuse, the soil may be remediated or classified for off-site disposal. Should these soils require off-site disposal, these soils should be classified appropriately in accordance with the *Environment Protection (Waste Resource) Regulation 2009* and associated Industrial Waste Resource Guidelines (IWRG) 631 (*Solid Industrial Waste Hazard Categorisation and Management*) prior to off-site disposal;
- Soil contamination could also present a potential risk to construction workers from contact with potentially contaminated soils (dermal contact or inhalation of vapours), to buildings and structures if the contamination is corrosive or to the environment if relocated to an environmentally sensitive area. Accordingly, it is recommended that human contact with any contaminated soil and groundwater should be avoided with appropriate use of Personal Protective Equipment and the implementation of a Construction Environmental Management Plan (CEMP) during the construction works;
- In the unlikely event that Potential Acid Sulphate Soils material is generated on site as a result of the construction works, this material should be investigated further. It is recommended that this issue be dealt with through the implementation of an CEMP; and
- Should potentially contaminated groundwater be encountered during the site construction activities, the groundwater should also be disposed of accordingly and appropriate health and safety measures put in place (i.e. preventing dermal contact or inhalation of vapours).

A. CARBON

A1. Energy use and greenhouse gas emissions

The following table outlines the expected overall level of energy use and energy related greenhouse gas emissions associated with the operation of the DGDP:

Type of energy use or greenhouse gas emission	Energy Use	GHG emissions intensity ('GGI') (tonnes CO_2-e/MWh "as generated")
Electricity generation	37.4–40.0 PJ/yr (Cases 1-3, coal + NG). 17.5 PJ/yr (Case 4, mostly NG).	0.73–0.78 (Cases 1-3, coal + NG) 0.45 (Case 4, mostly NG)
Non-energy related greenhouse gases	Energy use not quantified for Scope 3 emissions*	0.011–0.016 (Cases 1-3, coal + NG) 0.038 (Case 4, mostly NG)

*The non-energy related greenhouse gases; *i.e.*, due to diesel use by coal truck fleet, etc. While the energy of these disparate fuel types was not quantified, (it was not required for GHG emissions estimates), these 'Scope 3' emissions amounts were relatively small; *i.e.*, representing approximately 1.2–1.3% (Cases 1-3) and 8.2% (Case 4) of the calculated Scope 1 GHG emissions amounts.

A2. Best practice carbon management

The proposed DGDP facility itself, based on IDGCC technology developed by HRL, represents world's best practice with respect to utilisation of brown coal for electricity generation.

The DGDP will offer significantly lower greenhouse gas emissions per MWh of electricity generated than existing sub-critical brown coal fired power stations in the Latrobe Valley. Also, the DGDP is expected to exceed a performance standard estimate for 'supercritical brown coal'.

The current annual CO_2-e emissions of Latrobe Valley brown coal fired power stations are estimated to be approximately 57 Mt per annum. If new IDGCC technology with a GGI of 0.73 t CO_2 / MWh was to displace the current fleet of brown coal power stations this would result in annual savings of approximately 24 Mt of CO_2-e emissions per annum. It is expected that further savings of approximately 21 Mt per annum would be achieved with the development and implementation of Carbon Capture and Storage (CCS) technologies, if commercially feasible. The total savings of 45 Mt CO_2-e would equate to 8.3% of the total Australian CO_2 emissions (based on 2007 data).

The DGDP Cases 1-3 (0.73 - 0.78 tonne CO_2-e/MWh) have GGIs lower than all existing sub-critical black coal fired power stations in Australia.

The flexibility of the DGDP, allowing the use of lower greenhouse intensive natural gas as well as the abundant and (currently) lower cost brown coal also avoids the potential of an emissions lock-in for a 30-year plus project.

The DGDP provides a technology pathway for lower emissions from brown coal. As the provider of the IDGCC technology, HRL is also working with gas turbine suppliers to allow the use of syngas with the more efficient F class turbines in the future, (in comparison with E class turbines currently selected for the DGDP), which is expected to result in a 12% gain in efficiency.

With respect to best practice in the reduction of greenhouse gas emissions, the proposed DGDP represents a markedly improved technology for producing electricity from brown coal. The improvement is due to integrated drying and coal gasification allowing for improved brown coal emissions performance. It also provides a future technology development pathway for lower CO_2 emissions performance for the generation of power from brown coal.

B. WATER USE

B1. Water use

The main areas where water will be used in the Dual Gas Demonstration power station are listed in the table below.

Process step	Type of water use	Amount (ML/year)	Basis for numbers
Auxiliary plant cooling tower	Cooling tower make-up water	736	Mass balance calculations
Syn-gas cooling / cleaning	Recovered Water from Process	-148	Mass balance calculations / conservative estimate
ACC Water Sprays	Sprays to increase heat transfer in ACC	500	Operation when ambient temperature > 20°C
Gasification Process	Steam and water for temperature control.	492	Mass balance calculations
Demin plant drainage	Water consumption by demineralisation plant	181	Estimate
Gas Turbine NO_x Control	Steam	54	Mass balance calculations
Miscellaneous / Losses	Water consumption for miscellaneous plant and water losses (eg boiler leaks)	95	Estimate
Ammonia scrubber	Water consumption for ammonia scrubber	45	Mass balance calculations
Ash Plant	Make-up water demand from ashing system losses	25	Estimate
Total Water Consumption Estimate:		**1,980 ML/yr** (1.98 GL/yr)	

Source: Data provided by HRL, 18 June 2010

Further details of water consumption for the two operating scenarios are provided in the table below.

Process step	Type of water use	GTs Operating on 100% Natural Gas Water (tph)	GTs Operating on 100% Syngas Water (tph)
Auxiliary plant cooling tower	Cooling tower make-up water	0	99
Syn-gas cooling / cleaning	Recovered Water from Process	0	-20
Gasification Process	Steam and water for temperature control.	0	66
Demin plant drainage	Water consumption by demineralisation plant	23	23
Gas Turbine NO_x Control	Steam	124	0
Miscellaneous / Losses	Water consumption for miscellaneous plant and water losses	12	12
Ammonia scrubber	Water consumption for ammonia scrubber	0	6
Ash Plant	Make-up water demand from ashing system losses	0	3
Total Water Consumption Estimate:		159	189

Note estimates of water consumption above exclude air condenser cooling with water sprays, which shall only be operated for limited periods a year (during hot days) and shall not be used as part of normal operation.

B2. Best practice water management

Under the Environment Protection (Environment and Resource Efficiency Plans) Regulations 2007, the water consumption threshold for triggering the preparation of an Environment and Resource Efficiency Plan (EREP) is 120 ML per annum. As can be seen in the table above, once the DGDP becomes operational, this threshold will be triggered. However, an exemption from the preparation of an EREP is requested given the preparation of this EPA Works Approval (including sections A-D).

Water saving was a key criteria in the selection of process options. The DGDP is expected to use 75% less water per MWh than the best practice (in regards to water consumption) existing brown coal fired power station in the Latrobe Valley. Of the total water saving, around 40% is the direct result of using the IDGCC technology.

A second key design selection contributing to an additional about 35% water efficiency is the use of Air Cooled Condenser (ACC) technology. As described previously, condensate cooling options considered included both wet cooling system and air cooled condenser (ACC) technology. The advantages and disadvantages of each option were considered in detail (see Section 5.4) and ACC technology selected for its significant reduction in water usage.

Other water efficiency measures to be incorporated include:

- Most of the water obtained from the raw brown coal in the coal drying process remains as part of the syngas to add mass to the gas turbine flow, thus increasing power output.
- Extracted water from the syngas will also be used in the auxiliary cooling system and will reduce the make-up water requirement.
- Saline wastewater discharged from the ash sluice system will be reused (following settlement) in the closed ash disposal transport system.

C. SOLID WASTE

C1. Solid waste generation

Solid wastes produced on-site by the Dual Gas Demonstration Project are described in the table below.

The generation of waste from the demonstration power station will vary depending on the amount of time the plant runs on syngas and natural gas. For the purposes of this application, the waste tonnages listed in the table below for ammonium chloride, ammonium sulphate and ash have been calculated based on the demonstration power station running on syngas and therefore represent the upper maximum waste generation volumes.

Waste Type	Source	Amount (t/year)	Basis for numbers
Ammonium chloride and ammonium sulphate	Syngas clean-up system (prior to combustion in GT)	*25,000*	*Plant mass and energy balance, based on 85% capacity with 2 gasifiers operating on Morwell coal.*
Ash	Ash sluice system	*40,000*	*Plant mass and energy balance, based on 85% capacity with 2 gasifiers operating on Morwell coal.*
General wastes including putrescible & organic (food waste), recyclables including glass, plastics, aluminium, paper, cardboard, scrap metals and wood	Plant, workshops, offices, lunchroom	Approximately 6 tonnes per annum of waste/recyclables per staff member	*Based on 35 operations employees*
Hazardous waste including chemicals, solvents, paints, resins and materials from clean-up of chemical spills (eg absorbent materials).	Plant, workshops, offices, lunchroom	Minor. Quantity and composition likely to vary significantly day-to-day	*NA*

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C2. Best practice solid waste management

Waste management options are to be implemented in accordance with the waste hierarchy, as referred to in the *Environment Protection Act 1970*, which provides a list of preferences for waste management, with avoidance as the most preferable, followed by re-use, recycling, recovery of energy, treatment, containment and disposal.

The best practice solid waste management methods to be used are presented in the table below.

Waste Type	Management Method
Ammonium chloride and ammonium sulphate	Ammonium chloride and ammonium sulphate are by-products expected to be recovered by concentration and crystallisation and on-sold. Ammonium sulphate is used as a fertiliser. Dual Gas intends to seek potential buyers for this product (in crystalline form). Preliminary discussions have been held with potential buyers. Ammonium chloride is used as a feedstock in the galvanising industry - but is produced in only very small quantities. Dual Gas intends to sell either as a crystalline form or preferably in liquid form (to reduce capital outlay and extra processing steps). Further work is planned to explore markets for these products.
Ash	The ash discharged from the Project will be indistinguishable to the ash from a conventional brown coal fired power station in the Latrobe Valley. When the Dual Gas Demonstration Project is using coal from the mine adjacent to the proposed demonstration power station site water from the ash pond will be used to transport this ash for disposal into the ash pond. The disposal of the settled ash at the bottom of the pond is expected to be managed by International Power Hazelwood who manage the storage of this ash.
General wastes including putrescible & organic (food waste)	Collection on-site and stored in segregated area. Transportation by a waste contractor for off-site disposal at Morwell or Traralgon landfills.
Recyclables including glass, plastics, aluminium, paper, cardboard, scrap metals and wood	Segregation and collection on-site. Transportation by a waste contractor for off-site recycling.
Hazardous waste including chemicals, solvents, paints, resins and materials from clean-up of chemical spills (eg absorbent materials).	Collected on-site and stored in the designated waste storage area. Transportation off-site using a licensed commercial waste contractor. The Environment Protection (Prescribed Waste) Regulations will be adhered to for disposal of any potential wastes identified as Prescribed Wastes under these Regulations.

Excess soil excavated during site preparation and construction is expected to be used to construct an earth mound north of the proposed demonstration power station, within the EBAC site boundary, to mitigate visual impact from Princes Freeway and Commercial Road. This mound is expected to be landscaped and planted in native trees.

D. PRESCRIBED INDUSTRIAL WASTE

Prescribed industrial waste produced on-site by the Dual Gas Demonstration Project will include:

- **Fly ash** (40,000 tonnes per annum): - waste management described in the section above, to be handled in a manner consistent with normal power station practise in the Latrobe Valley;
- **Hazardous Wastes:** Minor quantities including chemicals, solvents, paints, resins and materials from clean-up of chemical spills (eg absorbent materials). The quantity of spent ion exchange resin consumed will depend upon a range of factors including raw water quality, quantity of water extracted from the process and quantity of water consumed by the process.

The *Environment Protection (Waste Resource) Regulation 2009* and its corresponding IWRGs will be adhered to for disposal of any potential wastes identified as Prescribed Wastes under these Regulations (eg ion exchange resins). For the hazardous wastes listed above, this shall include containment on-site and storage in segregated areas. These wastes will be removed from site and recycled or disposed of by a licensed contractor as required.

E. AIR

E1. Air emissions

The key pollutants associated with operation of the Dual Gas Demonstration Project are oxides of nitrogen (NO_x) and sulfur dioxide (SO_2); refer to section 4.2.2. The NO_x and SO_2 emissions for the proposed demonstration power plant reflect the two extremes of operation at full output; *i.e.*,

(1) 2 x gasifier operation providing full capacity for 2 x gas turbines operating on syngas, with maximum supplementary duct firing on natural gas; and

(2) 2 x gas turbines operating on natural gas at full output with maximum supplementary duct firing on natural gas.

Other pollutants were investigated also and a summary was provided in Section 7.1. A more detailed dataset of the estimated air emission rates is provided as the following table. The table includes HRL estimates for emissions of Class 3 substances (see Appendix F).

Modelled air emission rates are presented in the following table:

Process step	Type of air emission	Emission Rate (g/min)	Basis for numbers
CCGT Stack emissions (stacks 1 & 2)	NO_x - syngas with supplementary NG firing	Stack 1: 1,954 Stack 2: 1,954	Modelled emission rates - as described above.
	SO_2 - syngas with supplementary NG firing	Stack 1: 11,701 Stack 2: 11,701	
	NO_x - 100% NG operation	Stack 1: 1,711 Stack 2: 1,711	
	SO_2 - 100% NG operation	-	
	PM_{10} - syngas with supplementary NG firing	Stack 1: 358 Stack 2: 358	
	PM_{10} - 100% NG operation	Stack 1: 314 Stack 2: 314	
Char Burner Stack emissions	NOx - syngas with supplementary NG firing	Stack 1: 769 Stack 2: 769	Modelled emission rates - as described above.
	SO2 - syngas with supplementary NG firing	Stack 1: 553 Stack 2: 553	
	NOx - 100% NG operation	Stack 1: 84 Stack 2: 84	
	SO_2 - 100% NG operation	-	
	PM_{10} - syngas with supplementary NG firing	Stack 1: 124 Stack 2: 124	
	PM_{10} - 100% NG operation	Stack 1: 10 Stack 2: 10	
Air Pre Heater Stack emissions	NO_x - syngas with supplementary NG firing	Stack 1: 11 Stack 2: 11	Modelled emission rates - as described above.
	SO_2 - syngas with supplementary NG firing	-	
	NO_x - 100% NG operation	-	
	SO2 - 100% NG operation	-	
	PM_{10} - syngas with supplementary NG firing	Stack 1: 0.14 Stack 2: 0.14	
	PM_{10} - 100% NG operation	-	

/continued

Process step	Type of air emission	Emission Rate (g/min)	Basis for numbers
Pre dryer Stack emissions	NO_x - syngas with supplementary NG firing	Stack 1: 73 Stack 2: 73	Modelled emission rates - as described above.
	SO_2 - syngas with supplementary NG firing	-	
	NO_x - 100% NG operation	-	
	SO_2 - 100% NG operation	-	
	PM_{10} - syngas with supplementary NG firing	Stack 1: 44 Stack 2: 44	
	PM_{10} - 100% NG operation	-	
Class 3 indicator emissions from (all) the DGDP stacks	Alpha chlorinated toluenes and benzoyl chloride^	6.85E-04	▪ National Pollutant Inventory[1] emission factors used to estimate the emission rates ▪ Emission rates are average over a year, based on an annual coal consumption of 3,497,000 t [2] ▪ Where NPI emission factors were not available, but an emission factor calculated from the BCIRP[3] work was available, it has been used.
	Arsenic and compounds	2.00E-02	
	Benzene	2.40E-02	
	Beryllium and beryllium compounds	1.13E-02	
	Cadmium and cadmium compounds	1.66E-02	
	Chromium VI compounds	4.06E-02	
	1,2-dichloroethane (ethylene dichloride)^	4.59E-02	
	Dioxins and Furans (as TCDD I-TEQs)	5.85E-06	
	Nickel and nickel compounds	2.26E-01	
	PAH (as BaP)	5.32E-03	
	Pentachlorophenol^	6.85E-03	
	Respirable crystalline silica^	1.49E+00	
	Trichloroethylene	2.40E-02	
	Vinyl Chloride^	4.59E-02	

^ Indicates the emission factor is from the BCIRP study.

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[1] Australian Government, Department of the Environment and Heritage; *National Pollutant Inventory Emission Estimation Technique Manual for Fossil Fuel Electric Power Generation Version 2.4*; 15 March 2005

[2] Spreadsheet from HRLD "IDGCC – CO2 emissions V7.xls"

[3] Brown Coal Industry Research Program

E2. Best practice air emissions management

This section describes the approach taken to determine best practice for air emissions management.

Primarily, determination of best practice for using brown coal for electricity generation has been by research and development undertaken by HRL's engineering teams over many years, including trials of the technology in the Latrobe Valley near the current proposed site. With respect to air emissions today and in the future, in determining best practice for a power generation technology, the designer has had to strike a balance between reducing greenhouse gas emissions on the one hand, (the primary driver of best practice air emissions), while managing emissions of other air pollutants on the other.

While best practice greenhouse gas emissions has been the primary driver for the DGDP, a substantial amount of attention has been given to reducing emissions of the other air pollutants also; for example, reducing NO_x emissions as far as practicable, in this way. The DGDP will use ammonia scrubbing of the syngas with a design of 95% ammonia removal (to reduce fuel NO_x). Due to the use of the lower calorific value (compared with natural gas) syngas in the gas turbine, diffusion combustion technology must be used, and as such the Dry Low NO_x burners normally employed for combustion of natural gas are unable to be used. The use of syngas with gas turbine diffusion combustion technology normally employed for combustion of natural gas, means that conventional Dry Low NO_x burners cannot be used. As such to reduce thermal NO_x emissions under natural gas operation steam injection is used, resulting in a trade-off between efficiency and NO_x emissions.

In summary, the processes and technologies incorporated into the design of the DGDP, with a view to reducing emissions are:

- Syngas cleaning system for reducing particulate matter (see Section 5.2.5)
- Flue gas cleaning system for reducing particulate matter (see Section 5.2.5)
- Ammonia scrubbing of the syngas with a design of 95% ammonia removal to reduce NO_x formation
- Steam injection when gas turbines are operating on natural gas for NO_x control to reduce NO_x emissions
- Stack heights and exit velocities tested by air dispersion modelling of SO_2 and NO_x emissions (see section E3)

The fuel selection of Latrobe Valley coal also offers benefits to SO_x emissions due to the low sulfur content.

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Dual Gas will install and maintain a continuous emission monitoring system for the demonstration power station site to monitor air emissions from the exhaust stacks. Emissions monitoring will include measurement of NO_x (as NO_2, NO, oxides of nitrogen as NO_2 equivalent) and CO. There will also be continuous monitoring of particulate matter using opacity meters.

A detailed study of potential Class 3 indicators expected from the proposed DGDP was undertaken by HRL (refer to Appendix F). Some of the estimated emission rates from that study are provided in the previous section (E1). Of the suite of possible Class 3 substance emissions, this study indicated that most attention should be given to the Class 3 substances: beryllium, dioxins and furans, and Respirable Crystalline Silica (RCS). To some extent these Class 3 emissions will be controlled by reducing, wherever practicable, emissions of particulate matter from the plant.

Further more detailed information on the best practice air emissions control technologies selected are provided in section 5.1.4 (Environmental Controls) and Section 5.2 (Environmental Best Practice).

E3. Impact on air quality

Air dispersion modelling of NO_x and SO_2 emissions from the proposed demonstration power plant was undertaken utilising the advanced non-steady state model CALPUFF V 6.262, in accordance with the SEPP-AQM. The alternative modelling methodology and input data was approved by the EPA. The cumulative assessment accounted for emissions from other existing Latrobe Valley air emission sources; *i.e.*, Energy Brix, Hazelwood, Yallourn, Loy Yang A and Loy Yang B power stations, and Maryvale Paper Mill (see Section 4.2.2).

Two scenarios were modelled for a 1-year simulation period: (1) A dual gas (*i.e.* syngas and natural gas)-fuelled DGDP; and (2) A 100% natural gas-fuelled DGDP.

The air quality assessment for the proposed DGDP was undertaken in accordance with the Victorian SEPP-AQM. The SEPP-AQM provides Design Criteria that specify maxima (or near maxima) for air pollutant Ground Level Concentrations (GLCs), for investigating ambient air quality impacts or effects due to air emissions from stacks and other sources. Air emissions data are input to an air dispersion model to determine modelled GLCs for comparison with the relevant Design Criteria.

For the assessment of effects from the proposed DGDP, the air dispersion model 'CALPUFF' was used with an annual meteorological file developed using the TAPM and CALMET meteorological models and Latrobe Valley Air Monitoring Network meteorological data. A review of the 1991 Latrobe Valley meteorological data file showed compliance with US EPA protocols for the collection and processing of meteorological data for general use in air quality modelling applications. Comparisons of dispersion modelling results using the 1991 meteorological data file with measured data from more recent years indicated good agreement between the datasets. This was undertaken under the guidance of EPA.

The CALPUFF modelling covered a 51km x 31km region of the Latrobe Valley at a spatial resolution of 1km. Discrete receptors were included at various locations including the present day Latrobe Valley Air Monitoring Network stations located at Moe, Traralgon, Rosedale South and Jeeralang Hill. Four homesteads to the east and southeast of the proposed demonstration power plant identified as sensitive receptors by SKM (2009) were also included.

The CALPUFF-predicted 99^{th} percentile hourly average GLC results, *i.e.*, the cumulative ground level concentrations of NO_2 and SO_2 resulting from the DGDP (utilising full syngas production with supplementary natural gas firing) in conjunction with other air pollution sources in the Latrobe Valley are presented in the table below and compared with relevant Design Criteria.

Pollutant	Averaging Period	Design Criteria (ppm)	99.9th percentile modelled value (ppm)
Nitrogen dioxide	1-hour	0.10	0.05
Sulfur dioxide	1-hour	0.17	0.15

Similarly, the CALPUFF-predicted GLCs for NO_2 resulting from 100% natural gas operation in conjunction with other emission sources in the Latrobe Valley is presented in the table below and compared with relevant Design Criteria.

Pollutant	Averaging Period	Design Criteria (ppm)	99.9th percentile modelled value (ppm)
Nitrogen dioxide	1-hour	0.10	0.05

In both cases (dual gas scenario and natural gas scenario), the model-predicted GLCs for the two key air pollutants for the DGDP are significantly less than the relevant SEPP-AQM Design Criteria.

F. WATER DISCHARGES

F1. Water discharges

Current water discharges

Waste water from the existing EBAC's cooling towers and storm-water run-off flow from the site through a storm water drainage system to a settling pond located approximately 500 m northwest of the Dual Gas demonstration power station site. Suspended solids and particulate organic matter settle in the pond bed before the supernatant is discharged into Bennetts Creek intermittently. Discharges from the settling pond into Bennetts Creek operate under an EPA discharge licence held by EBAC. Water quality in the settling pond and Bennetts Creek is monitored on a daily basis.

Proposed water discharges

The following table identifies the sources, types and expected discharge volumes.

Process step	Type of water discharge	Discharge location	Flowrate (L/day)	Description	Basis for Figures
DGDP site	Storm-water run-off	Bennetts Creek	Rain dependent	There is expected to be a likely reduction in the amount of particulate material in the run-off from the site. This could mean a decrease in the accumulation of particulate organic matter in the settling pond but also an increase in pollutants that typically runoff from impervious industrial surfaces, such as phosphorus (P), nitrogen (N) heavy metals and total suspended solids. If the operation of the settling pond does not change then this could mean a slight increase in variables such as P, N, and heavy metals in the water discharged from the settling pond to Bennetts Creek. However, the operation of the EBAC Settling Pond will be such that it continues to meet environmental license requirements.	NA

Process step	Type of water discharge	Discharge location	Flowrate (L/day)	Description	Basis for Figures
Ash sluice system	Saline ash water	Hazelwood Ash Pond	4,000,000 litres / day	Saline wastewater discharged from the ash sluice system into the Hazelwood Ash Pond will be recycled, after ash and other particles are settled at the bottom of the pond, and returned to the proposed demonstration power station to be reused in the closed ash disposal transport system.	From mass balance calculations, based on 5% slurry
Excess water from Hazelwood Ash Pond	Saline water	Discharged via the Saline Water Outfall Pipeline (SWOP) system as per existing industry arrangements	80,000 litres / day	The additional saline water discharge associated with the Dual Gas Demonstration Project is not expected to have significant impacts on the quality of water discharged to the ocean via SWOP.	Based on 2% bleed of the ash sluice flow
Construction phase	Any waste water from the DGDP site construction activities and storm-water run-off	Water will be treated by the existing settling pond prior to discharge to Bennetts Creek	Rain dependent	Suspended solids and particulate organic matter settle in the pond bed before the supernatant is discharged into Bennetts Creek. The operation of the EBAC Settling Pond will be such that it continues to meet environmental license requirements.	NA

F2. Best practice water management

Water quality and quantity of run-off from the project site will be managed in accordance with Urban Stormwater Best Practice Environmental Management Guidelines (BPEMs), published by CSIRO in 1999. At all times the operation of the EBAC Settling Pond will be such that it continues to meet existing environmental license requirements.

As detailed in Section F1, saline water from the demonstration power station will be discharged to the HAP. The supernatant in the HAP will be withdrawn and returned to the demonstration power station for reuse in a closed loop system. Excess water in the Ash Pond will be discharged via the Saline Water Outfall Pipeline (SWOP) system as per existing industry arrangements. This is considered to be the best practice, as it allows maximum re-use of a saline water source and only excess saline water is discharged to the ocean – a compatible saline environment.

During construction, water discharges will also be managed in accordance with the EPA Guidelines for Major Construction Sites (Publication No. 480).

F3. Impact on waterway

An assessment of the potential aquatic ecological constraints associated with the proposed development of the DGDP has been undertaken. The study focused on potential ecological impacts to Bennetts Creek, located immediately east of the proposed demonstration power station site and is a left bank tributary of Waterhole Creek.

Bennetts Creek was assessed for in stream habitat condition, water quality and fish values that will potentially be impacted by the construction and operation of the demonstration power station, infrastructure and transmission line. The survey determined Bennetts Creek to be a highly modified and relatively degraded waterway. The fish survey did not identify any fish species in the proposed construction corridor or upstream.

The DGDP site falls under the SEPP *Insertion of Schedule F5 – Waters of the Latrobe and Thompson River Basin and Merriman Creek Catchment (Segment E)*. Beneficial uses in this area include highly modified ecosystems with some habitat values, water based recreation (primary and secondary contact), aesthetic enjoyment, commercial and recreational use, agricultural water supply, fishing and aquaculture, industrial water use and aquifer recharge.

The planned footprint for the proposed approximate 600MW demonstration power station is approximately 200m on average from Bennetts Creek. There is limited work activities expected from the construction and operation activities of the demonstration power station, which will be any closer than this to the waterway. Any movements of trucks for access should be minimised in this area and storage of temporary structures is not recommended in this area. Given the distance, the expected impacts to aquatic species and habitat in Bennetts Creek will be minimal.

An assessment of the existing water quality in Bennetts Creek has been undertaken and the results are presented in the table below.

- **Water quality in Bennetts Creek on the 12th November 2009, the SEPP guidelines and the licence limits for the discharge point**

	Unit	Site 1	Site 2	Site 3	Site 4	Site 5	Site 6	Site 7	License Limit	SEPP (90th percentile)[2]
Temp	^0C	19.6	n/a [1]	22.7	21.9	n/a [1]	24.2	21.2	n/a 1	rate of change <1.0 in 30 mins
pH	pH units	7.42	n/a [1]	7.41	7.18	n/a [1]	8.85	7.33	6.0-8.5	6.0-8.5
EC	mS/cm	3.29	n/a [1]	5.13	0.806	n/a [1]	0.433	0.516	n/a 1	<0.833 mS/cm (<500 TDS mg/L)
Turbidity	NTU	79	n/a [1]	29	2	n/a [1]	n/a 1	n/a 1	50	<25 (max<50)
DO	mg/L	3.9	n/a [1]	2.81	4.4	n/a [1]	n/a 1	3.6	n/a 1	Min. conc. >5.0

n/a[1]: no records taken because of failure of equipment

[2] *SEPP (Waters of Victoria)* - *Insertion of Schedule F5, Waters of the Latrobe and Thomson River Basins and Merriman Creek Catchment (Segment E) (State of Victoria 1996).*

Considering the current water quality we would expect that limited flora and fauna could inhabit Bennetts Creek in this condition. Also given the limited impacts from the construction and operation activities of the DGDP, as previously mentioned, it is considered unlikely that the project will significantly impact the water quality of Bennetts Creek.

G. LAND AND GROUNDWATER

G1. Discharge or deposit to land or groundwater

There are no proposed waste water discharges or deposits to land. However, given the flat topography and the proximity of Bennetts Creek to the site, this creek is considered to be a potential receptor of any groundwater impact originating from the proposed demonstration power station site and transmission line route.

G2. Best practice land and groundwater management

The best practice land and groundwater management strategies for this project are:

- Conducting contaminated land assessment works in accordance with established protocols, including SEPP *Groundwaters of Victoria*, SEPP *Prevention and Management of Contamination of Land*, NEPM (Assessment of Site Contamination), Australian Standard AS4482.1: *Guide to the investigation and sampling of sites with potentially contaminated soil* Part 1 and 2;
- Application of the waste hierarchy in the management of all wastes;
- Development and implementation of an EPA approved Environmental Improvement Plan which sets out how contamination will be prevented;
- The quality and quantity of water run-off from the project site will be managed in accordance with the Urban Stormwater Best Practice Environmental Management Guidelines (BPEMs), published by CSIRO in 1999.

Other management measures:

- A Phase 2 Environmental Site Assessment intrusive investigation will be undertaken to further assess potential soil and groundwater contamination at the site prior to earthworks and the relocation of soils so that additional management measures can be developed if required;
- The removal and reuse of soils on site will be managed through the implementation of a site soil management plan. Should these soils require off-site disposal, they will be classified in accordance with the *Environment Protection (Waste Resource) Regulation 2009* and associated Industrial Waste Resource Guidelines : IWRG 631 (*Solid Industrial Waste Hazard Categorisation and Management*) and IWRG 702 (*Soil Sampling*) prior to off-site disposal;

- Excavation works in the vicinity of the asbestos cement piping be managed by an appropriately qualified subcontractor.
- Waste soils will be battered in the north of the former ash pond within the EBAC complex (but outside of the proposed project site) and landscaped to prevent the contamination of proposed relocation sites.

G3. Impact on land and groundwater

The Phase 1 Environmental Site Assessment for the project identified a number of potential existing sources of contamination on and off-site. Potential on-site sources include the following:

Asbestos Cement Piping

A 100 mm diameter asbestos cement pipe runs in a north-south direction in the western half of the project site where excavation work is proposed to level the site. The asbestos is considered to be a potential source of contamination if encountered and damaged (with subsequent asbestos fibre release) during the development. As the materials will be dealt with by an appropriately qualified subcontractor the risk of additional contamination is considered low.

Potential Acid Sulfate Soils

A review of the Australian Soil Resources Information System (ARIS) map indicated that soils with a high probability of acid sulphate soil occur within 2 km of the project site. Based on this information there is the potential for acid sulphate soils on site. As the maximum depth of excavation works associated with the project will not exceed 2 m below ground level it is considered unlikely that coal deposits will be encountered during construction but there is a low potential for acid sulphate soils to be generated.

Potential off-site sources of contamination include:

Energy Brix Power Station and Briquette Manufacturing Facility

There is a high risk that subsurface soil and groundwater contamination has occurred on these off-site facilities and migrated on to the project site (depending on the groundwater flow). This is due to the location of these facilities (directly adjacent to the site), the period of time that they have been operating on the site (over 50 years) and the variety of heavy industrial activities that they utilise. Potential contaminants include heavy metals, TPH, PAHs, solvents (VOCs) and PCBs.

Former Ash Pond

There is a high risk that subsurface soil and groundwater contamination from this off-site location has migrated on to the project site (depending on the groundwater flow). This is due to the proximity of the pond to the project site (directly adjacent to the site).

In addition to the above, the Site Assessment identified the potential for construction works associated with the project to lead to additional contamination through the movement of waste soils. Given this, it is proposed that waste soils generated during site preparation and construction works be battered in the north of the site against the existing northern boundary of the former ash pond and landscaped. A site soil management plan will be developed to reduce the potential for contaminated soils being relocated elsewhere on site and contaminating relocation sites.

H. NOISE EMISSIONS

H1. Noise emissions

Potential noise emissions from the demonstration power station were identified through noise modelling techniques based on SoundPLAN computer software. This software has been designed for the particular application of analysing noise emissions from industrial sources and has been validated through practical tests for a sound range of 100-2000 metres. In order to generate the model, the demonstration power station was separated into a number of components with Sound Power data specific to each component applied. The various components identified for modelling are based on their differences in acoustic properties and include:

- Combined Cycle Gas Turbine (CCGT) and Heat Recovery Steam Generator (HRSG)
- Integrated Drying and Gasification Plants
- Char Boiler
- Steam Turbines and Generators (STG)
- Air Cooled Condensers
- Nitrogen Plant
- Sundry Equipment.

The available sound power level data for the various components of the plant was very limited due to the inability of the manufacturers to supply the noise data information at this point in time. The sound power level data applied to various pieces of equipment have therefore been derived from an equipment data bank and from noise data of equipment of a similar configuration used for other power station projects.

The derived Sound Power Levels for the various components and assumptions utilised for their establishment can be viewed under section 5 in the Noise Assessment Report provided as Appendix E to this report.

H2. Best practice noise management

Ascertaining best practices for noise management involved investigating appropriate measures for evaluating an acceptable noise level criteria at the applicable receivers, whilst also predicting noise emissions from the source to be evaluated at each of the receivers.

The evaluation of applicable noise criteria involved adhering to practices outlined by the EPA Victoria and included acceptable noise levels in accordance with draft State guidelines "Noise From Industry in Regional Victoria (Publication 1316, December 2009)". In addition, the measurement of background noise at identified receivers was established in accordance with the processes outlined in the State Environment Protection Policy No. N-1 "Control of Noise from Commerce Industry and Trade". Application of both these processes as part of a noise criteria evaluation strategy ensures that all aspects (including zoning, locality and those unique to the particular environment being assessed) are incorporated in an acceptable manner to EPA Victoria and therefore best practice.

The evaluation of predicted noise emissions from the demonstration power station involved an assessment of suitable modelling techniques. The application of computational modelling using the soundPLAN software was assessed as the most suitable for the following reasons:

- Specific for application with industrial sources
- Software model has been tested in the field and validated to distances expected at residences for evaluation as part of this noise assessment
- Recognised acoustic model for predicting sound emission by various agencies both nationally and internationally (including EPA Victoria)

In addition, computational modelling was assessed as the most appropriate method due to the fact that the demonstration power station being assessed is yet to achieve commercial application and therefore relies on indicative data developed for individual components. A computational modelling program has the flexibility to accommodate various data inputs and associated assumptions to provide an overall predicted sound emission level.

H3. Noise impact

Noise criteria and the predicted sound pressure levels ascertained for the worst case scenario at each of the two residences are outlined in Table H3.1 below. Values for noise criteria over all time periods and all modelling scenarios can be viewed in the Noise Assessment Report provided as Appendix E to this report.

- **Table H3.1: Worst Case Predicted Sound Pressure levels and Most Critical Noise Limits**

Location of receptor(s)	Predicted Worst Case Noise levels from project^	Existing noise levels (site)^	Background noise level^	Total noise level^	Most Critical Noise limit^
30 Church Rd, Hazelwood	34.5 (29.5 with noise mitigation)	-	42 (Evening Period)	42.5 (42 with noise mitigation)	47 (Evening Period)
46 McLean St, Morwell	45.5 (40 with noise mitigation)	-	35 (Night Period)	45.5 (41 with noise mitigation)	40 (Night Period)

I. ENVIRONMENTAL MANAGEMENT

I1. Non routine operations

The significant environmental operational risks and their associated environmental impacts for non-routine events have been identified and are detailed in the table below. The table also lists management strategies to be employed to reduce the potential for environmental impacts. Such strategies will be implemented through a site Emergency Response Plan.

Process upsets	Environmental Impacts	Management Strategies
Fire or Explosion	• Air emissions • Potential water discharge/runoff • Soil contamination • Exposure to hazardous substances	• Detection/alarm system • Emergency response plan
Uncontrolled gas release	• Air emissions • Potential water discharge/runoff • Soil contamination • Exposure to hazardous substances	• Detection/alarm system • Emergency response plan
Firewater runoff	• Potential wastes include Aqueous film Forming Foam (AFFF) deluge water and hydrocarbons and other chemicals.	• As part of the site emergency response procedures, any fire on-site will trigger a requirement to isolate any off-site discharge points. • Once the fire has been extinguished, any fire fighting liquid contained in bunds will be manually pumped out and discharged off site to sewer in compliance with the site's trade waste agreement. • Adequate spill containment materials will be maintained on-site at all times and used to prevent runoff of any fire fighting liquids not contained within bunded areas. Contained water will then be treated if required, prior to being discharged off site to sewer in compliance with the site's trade waste agreement.

		• Alternatively, contained liquids will be removed and disposed of by an approved contractor as required. • Training in the Emergency response practices is to be provided when the demonstration power station first becomes operational and at an ongoing frequency as required.
Uncontrolled hydrocarbons /chemical releases due to failure, malfunction or leaking connections	• Contamination of Bennetts Creek/ Waterhole Creek	• Minor leaks can be treated or controlled on site by the site personnel if it is considered safe to do so, using spill kits. • Contact External Emergency Agencies if the extend of the incident is beyond the capacity of inhouse resources • All stormwater run-off will be directed to the settling pond, where any potential contamination will be retained. • Discharge to Bennetts Creek will occur only under controlled conditions, in accordance with the EPA discharge licence; • Bunding to be used around all acid tanks to contain any accidental leaks of acid.
Steam releases from safety release valves (generally associated with a plant trip or other unexpected significant variation in plant operating conditions)	• Noise emissions	• Noise from safety release valves would be considered as part of the design (e.g. Silencers will be fitted if practicable). • It is not possible to limit safety valve operation to daylight hours.

The DGDP site is located 1.3 km from the nearest residential area (Morwell). This buffer distance is considered acceptable as it complies with EPA's recommended minimum buffer distance of 1,000 metres, as prescribed in EPA publication *AQ2-86 Recommended Buffer Distances for Industrial Residual Air Emissions*.

12. Monitoring

Dual Gas will implement a routine environmental monitoring program in accordance with requirements of the EPA licence and State Environmental Protection Policies. An outline of the expected monitoring program is provided below.

This monitoring program will be further refined in consultation with the EPA and once the EPA licence limits are confirmed.

Air

Dual Gas will install and maintain a continuous emission monitoring system for the demonstration power station site to monitor air emissions from the exhaust stacks. Emissions monitoring will include measurement of NO_x (as NO_2, NO, oxides of nitrogen as NO_2 equivalent) and CO. There will also be continuous monitoring of particulate matter using opacity meters.

Noise

Should noise complaints be received, Dual Gas will investigate and, if applicable, implement a noise monitoring program. If noise monitoring indicates that the noise limits are exceeded, Dual Gas will further investigate the cause of the exceedence and implement practicable and feasible measures, as appropriate, to resolve the issue.

Noise monitoring will be undertaken in accordance with the procedures contained in State Environment Protection Policy No. N-1 (Control of Noise from Commerce, Industry and Trade) and the Guide to the Measurement and Analysis of Noise (EPA Publication IB280).

Greenhouse Gas Emissions

Greenhouse gas emissions will be calculated on a monthly basis using NGERS compliant methods. Dual Gas will report on an annual basis greenhouse gas emissions, energy production and energy consumption in accordance with the *National Greenhouse and Energy Reporting Act 2007*.

The following table proposes a schedule of monitoring for the demonstration power station:

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Process	Indicator measured	Monitoring type	Monitoring frequency	Use of monitoring
Water use	Water consumption	Flow meter	Continuous	Billing purposes
Water discharges from the settling pond to Bennetts Creek	Suspended solids PH Colour TDS Turbidity Temperature	Water quality monitoring, undertaken as part of EBAC's existing environmental monitoring program	Daily	To confirm compliance to SEPP and EPA Licence limits.
Noise emissions from operation of plant	Sound Power Levels dB(A)	Compliance monitoring	As required	To confirm compliance
Air emissions	NO_x, SO_2 against SEPP (Air Quality Management) criteria	Performance monitoring Compliance monitoring	Continuous online monitoring	SEPP & EPA licence compliance
Electricity use and generation	GHG & Energy use	Performance monitoring NGERS reporting requirement	Continuous online monitoring	To improve efficiencies. NGERS reporting
Various	General Solid Waste	Waste transfer certificates	As required	

12. Control Measures

Dual Gas will implement a series of control measures to help ensure that air and water emissions and noise pollution is kept within EPA licence limits and in accordance with State Environmental Protection Policies. Exceedances observed during monitoring shall be controlled using the following measures.

Air Emissions

NO_x emissions from the gas turbines (when operating on natural gas) will be controlled with the use of additional steam.

NO_x emissions from the gas turbines (when operating on syngas) can be reduced by altering the pH level (by acid addition) of the circulating liquor for the ammonia scrubber, used to remove ammonia from the syngas, which would otherwise form NO_x in the gas turbine.

High CO emissions in the HRSG stacks would likely only occur during duct firing with natural gas which brings down the excess air levels. The short-term control measure would be to temporarily reduce the duct firing to increase excess air levels. Longer term controls would be by modification to the duct burners to ensure low CO emissions during operation.

Particulate emissions from the char burner would most likely be due to a bag failure, which would require inspection and repair. Spare bags will be kept in store. An ongoing bag filter maintenance and inspection program shall be implemented. CO emissions from the char burner will be controlled through adjustment of excess air levels. NO_x shall be controlled through burner performance optimisation (including excess air level control, boiler fine-tuning and balancing of fual and air flows to the burners).

Water Emissions

A series of control measures shall be used to prevent spills of liquids from reaching the land environment. These shall include:

- Use of bunding around all acid tanks;
- Control of minor leaks on site by site personnel using spill kits;
- Directing all stormwater run-off to the settling pond to settle out any suspended solids and particulate organic matter;
- Discharge of saline water to the ocean via SWOP.

Noise

Specific noise control measures will be incorporated as part of the engineering design of DGDP, which shall be evaluated on their technical, operational and safety merits. This may include:

- Consideration of noise in the selection of plant components (eg use of low noise fans and pumps);
- Installing noise walls and panels where required;
- Use of acoustic enclosures;
- Installing silencers on safety valves (if considered to be practical);
- Development of an ongoing engineering maintenance program to assist in noise mitigation.

If a specific noise level exceedance for the operating plant is identified the source of the noise shall be identified, and a technical, operational and safety review of mitigation actions shall be conducted and appropriate action taken where required.

Further specific control measures are provided in Appendix E.

Greenhouse Gas Emissions

Greenhouse gas emissions can be controlled through a blend of syngas and natural gas. The blend ratio of the two fuels shall depend upon a range of operational and commercial factors, as discussed separately in this report.

Development of a maintenance and inspection program shall be used to maximise the efficiency of plant operation, resulting in reduced greenhouse emissions.

Utilities Failure Response Strategy

Utilities failure will have an effect on operations of the operation of the power station, as described below:

- **Natural Gas Supply:** A failure of the natural gas supply will result in a requirement to shut-down the power station, as natural gas is required for operation of the DGDP. DGDP will have a certain reserve of natural gas in the connecting pipeline upon which to draw down to enable a controlled shut-down of the power station. Sudden loss of natural gas would result from a rupture (or equivalent) of the supply line to DGDP, which would active an Emergency Shut Down (ESD);
- **Water Supply:** Water supply is required for continual operation of the DGDP. Sufficient water shall be stored on-site to allow a normal shut-down of the power station;

- **Power Supply:** Loss of an ability to export power will result in an ESD. Loss of the ability to import power will not require immediate action on the power station operation as the power station can supply the power required for internal use.

Loss of utilities can be appropriately considered in the development of the Emergency Shut-down (ESD) Procedures and in conducting the HAZOP studies.

9. CONCLUSION

This document provides the technical details to support the works approval application for the Dual Gas Demonstration Project. This application includes a description of the proposed project and an assessment of predicted greenhouse gas emissions, air emissions, water use, noise emissions, surface water discharges, energy use, solid waste and land and groundwater impacts associated with the project.

The key environmental issues related to the DGDP have been identified as greenhouse gas emissions, air quality, water usage and noise. Specialist studies undertaken for each of these aspects are provided as Appendices in support of the works approval application.

Approval is requested from the EPA to construct and operate the demonstration power station as the facility is defined as a Scheduled Premise (K01 – Power Stations) under the Environment Protection (Scheduled Premises and Exemptions) Regulations 2007.

APPLICANT STATEMENT

I declare that to the best of my knowledge the information in this application is true and correct, that I have made all the necessary enquiries and that no matters of significance have been withheld from EPA.

Signed CEO or delegate

Name: Paul Welfare

Position: General Manager (Dual Gas Pty Ltd)

Signature: Paul Welfare

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Appendix A Dual Gas Certificate of Incorporation

Certificate of Registration on Change of Name

This is to certify that

HRL DEVELOPMENTS (IDGCC) PTY LTD

Australian Company Number 117 102 244

did on the fifteenth day of April 2009 change its name to

DUAL GAS PTY LTD

Australian Company Number 117 102 244

The company is a proprietary company.

The company is limited by shares.

The company is registered under the Corporations Act 2001 and is taken to be registered in Victoria and the date of commencement of registration is the eleventh day of November, 2005.

Issued by the
Australian Securities and Investments Commission
on this fifteenth day of April 2009.

Anthony Michael D'Aloisio
Chairman

CERTIFICATE

081 04

Appendix B Water Use Desktop Assessment

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Dual Gas Demonstration Project

WATER USE DESKTOP ASSESSMENT

- Final
- 20 August 2009

Dual Gas Demonstration Project

WATER USE DESKTOP ASSESSMENT

- Final
- 20 Augut 2009

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Executive summary

The main purpose of this desktop assessment is to identify the source(s) of water supply to the project and identify potential impacts that proposed construction and operations will have on the delivery of environmental water requirements in the Latrobe River system. This desktop assessment also highlights the potential implications of climate change on the water supply to the project.

Information provided by HRL identifies that, following discussions with DTF and DSE, Dual Gas has been provisionally provided a 2GL/yr water allocation from Blue Rock Dam at 95% reliability for their operations. This allocation is to be supplied from the State Electricity Commission Victoria (SECV) unused entitlement.

During the construction phase, the water requirement has been estimated at 20 ML/yr. This volume during construction is negligible in relation to both existing entitlements in the Latrobe Valley and river flows. The supply of this water will likely need to be arranged with Gippsland Water if the proposed allocation is not in place by the onset of construction.

It has been estimated in recent studies (SKM, 2008) that highly reliable (>99% annual reliability) supply from the SECV's share is approximately 19 GL/yr under a repeat of historical conditions, but only around 11 GL/yr under ongoing low flow conditions post 1997. The entitlement to be secured for the project, which is likely to be a fraction of the SECV share, needs to take into account likely future reductions in water availability due to climate change.

The additional 2GL/yr of diversion by Dual Gas may result in a small reduction in the flows currently available to the environment (Latrobe River downstream of Lake Narracan and Gippsland Lakes). However, compliance with the currently legally enforced environmental flow requirements for the Latrobe River, described in Southern Rural Water's Bulk Entitlement conversion order, will not be affected. As these minimum passing flow requirements need to be satisfied prior to allocating any water to users in the catchment, their compliance will not be influenced by any future diversions for the proposed project.

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1. Introduction

1.1. Purpose and scope of the study

This report is a desktop assessment of the issues related to water supply to the proposed Dual Gas Demonstration Project. The main purpose of this assessment is to identify the source(s) of water supply to the proposed project and identify potential impacts that proposed construction and operations will have on the delivery of environmental water requirements in the Latrobe River system. This desktop assessment also highlights the potential implications of climate change on the water supply to the proposed facilities.

1.2. Methodology

Sinclair Knight Merz Pty Ltd (SKM) has reviewed the proposed water supply arrangements to the proposed power station. The likely reliability of this supply was then identified using existing information from past assessments of water availability in the Latrobe River system undertaken by SKM (2008).

It is essential that the water supply to the proposed power station be safeguarded from potential shortfalls. Shortfalls can occur if the volume of water made available to the power station through its licence or Bulk Entitlement[1] is insufficient at any time. Bulk entitlements in the system are generally based on a share of inflows to the system. The volume available under these entitlements has decreased significantly over the last 10 years of drought. Thus, it was necessary that an assessment of the potential impact of on-going low flows in the catchment from the post-1997 period be undertaken. The potential impact of ongoing low flows in the Latrobe River catchment was assessed using the findings from the SKM (2008) report. In each case, potential impacts on the environmental water requirements in the Latrobe River have been discussed.

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[1] **Bulk Entitlement**
A Bulk Entitlement (BE) is a right to use and supply water which may be granted to water corporations, the Minister for Environment and other specified bodies (DSE, 2009). It is a right to an amount of water that can be taken or stored under specific conditions/specifications up to a maximum volume.
BE's are issued along with a range of conditions and obligations set out under Part 4 of the Water Act 1989. A BE can be held in relation to water in a waterway, water in storage works of a water corporation and groundwater.
A bulk entitlement is usually specified in one of two ways:

- "**source**" bulk entitlement – is an entitlement to harvest water directly from a water source and which typically describes the different sharing arrangements at that source. Source entitlements can cover multiple storages operated in an integrated way within a river basin.
- "**delivery**" bulk entitlement – is an entitlement to be supplied water from another water corporation's dam or within a system which is regulated by the works of another corporation.
-

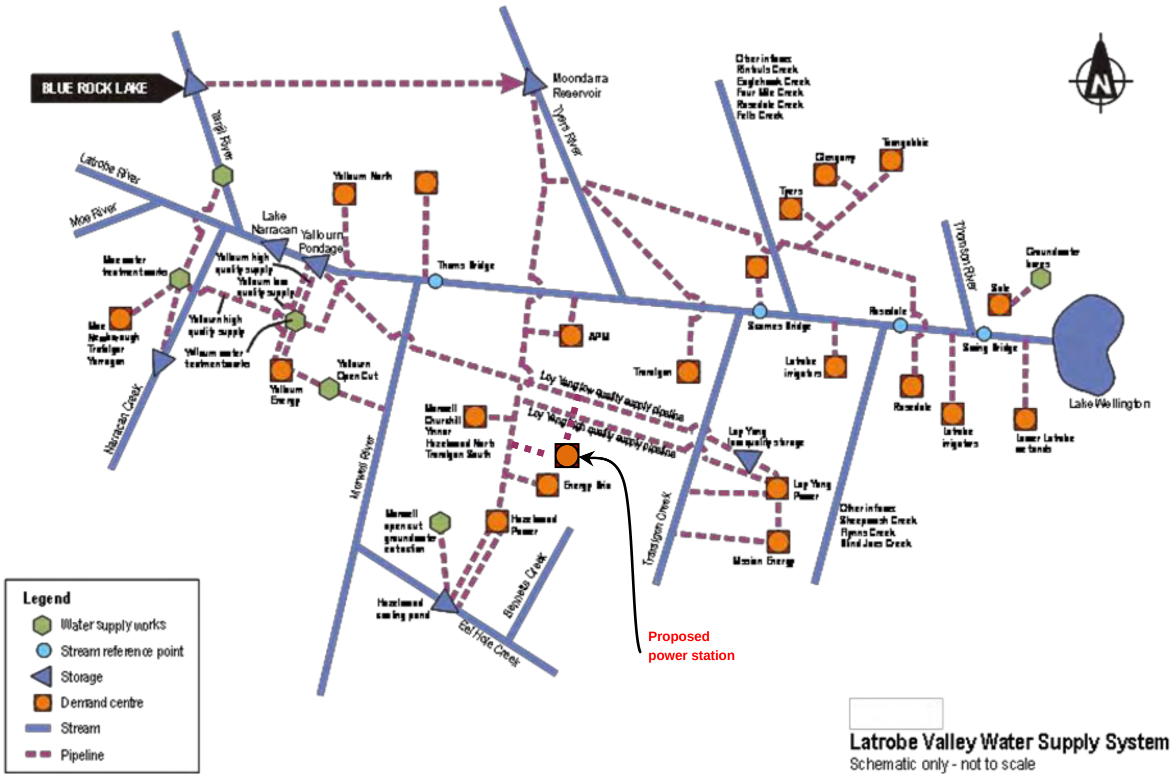
2. Background Information

2.1. Water resources in the Latrobe River System

The Latrobe River basin is the major source of catchment runoff for the region. Figure 1 provides an overview of the water resources distribution in the system and identifies the location of the Dual Gas Demonstration Project site and its potential water supply sources.

Streamflow in the Latrobe River and a number of its tributaries is captured in reservoirs and smaller storages to supply power companies, irrigators, urban areas and rural water systems.

Southern Rural Water operates Blue Rock Reservoir, located on the Tanjil River, and Narracan Creek, and manages the supply of raw water from these sources. Gippsland Water supplies water partly from Blue Rock Lake and partly from Moondarra Reservoir, located on the Tyers River.



■ **Figure 1: Latrobe water supply system schematic (Source: DSE, modified with permission)**

Historically, the Latrobe system has provided an estimated average, reliable yield of approximately 210 GL/year (at >99% reliability). However, average inflows over the past 10 years could sustain a reliable yield of only 151 GL/year. A breakdown of the estimated yield from the system was provided in SKM (2008), shown in Table 1.

- **Table 1: System yield to various users under historical and post-1997 flow scenarios (Source: SKM (2008))**

Source/Demand	Volume (ML) – Historical Flows	Volume (ML) – Post 1997 Factored Flows (Annual Factor)
Total inflow to the Latrobe River	830,000	536,000
Estimated Latrobe River system yield	210,000	151,000
Losses	16,000	15,000
Change in storage	-3,090	-380
To Gippsland lakes (not incl. Thomson inflow)*	617,000	380,000

*This assumes full utilisation of the currently unused SECV's BE and of the unallocated share in Blue Rock.

2.2. Environmental Water Requirements

One of the fundamental principles of sustainable water management in Victoria is that a healthy economy and society is dependent on a healthy environment. Increasingly, it is recognised that the sustainability of our water resources relies on healthy rivers and catchments. To determine these environmental needs, environmental flow studies are progressively being carried out for the region's major river systems (Gippsland Water, 2007).

Environmental flow studies have been undertaken for the Latrobe River by the West Gippsland Catchment Management Authority (WGCMA). These studies provide minimum recommendations for flow rates required at various stages of the year to maintain a 'healthy' alternative to the ideal natural flow regime. These recommended minimum flows are not legally binding and have only been used so far to assess current levels of compliance. They represent a target for sustainable water management in the Latrobe Valley which the State Government is working towards. While an environmental entitlement for the Latrobe River has yet to be determined (DSE, 2006), the Government has assigned 10,000 ML per year to the Latrobe River on a temporary basis from the unallocated share of Blue Rock Reservoir. The environmental allocation to the Latrobe River is for a 7 year period, until 2013, while investigations of environmental water needs are undertaken (Gippsland Water, 2007).

3. Water Supply Arrangements for the Proposed Project

3.1. Proposed water supply arrangements

Information provided by HRL identifies that, following discussions with the Victorian Department of Primary Industries, Department of Treasury and Finance and the Department of Sustainability and Environment,, a 2GL/yr water from Blue Rock Dam and Latrobe River at 95% reliability has been provisionally allocated for the operation of the proposed power station. A 95% reliability corresponds to Gippsland Water's level of service commitment to their urban customers in the Latrobe valley (Gippsland Water, 2007).

This allocation is subject to Ministerial confirmation which will be sought when Dual Gas is able to confirm unequivocally the Morwell site for the location of the Dual Gas Demonstration Project.

During the construction phase, the water requirement has been estimated at 20 ML/yr, which is much smaller than the requirement during the operation of the plant. If the proposed allocation is in place by start of construction, it could be accessed for the required water. If this is not case, this water could be bought from Gippsland Water or from other power stations. Gippsland Water could supply water using the existing pipeline to Energy Brix, while other power stations in the locality could provide some access to their raw water supply from Lake Narracan.

HRL Developments will be required to enter into commercial negotiations with Gippsland Water and Southern Rural Water on the delivery of potable and raw water respectively to the Dual Gas Demonstration project site.

3.1.1. Legal arrangements

Dual Gas's access to raw water from the Latrobe River system is understood to be defined as a share of the 3-4 Bench Bulk Entitlement.The exact share however is as yet undefined, as the volume available to the 3-4 Bench is inflow dependent, as specified in the Bulk Entitlement Conversion Order issued for the State Electricity Commission Victoria (SECV), which is included in Appendix B.

The SECV's Bulk Entitlement is primarily a '**source**' bulk entitlement, describing access to 10.43% of inflows to Blue Rock Dam up to an annual maximum of 12,000ML and 15.61% of unregulated flow into Lake Narracan up to an annual maximum of 25,000ML, after required passing flow requirements have been met.

3.2. Reliability of Supply

It has been estimated in recent studies (SKM, 2008) that the reliable supply (>99% reliability) from the SECV's share is approximately 19 GL/yr under a repeat of historical conditions, but only around 11 GL/yr under ongoing low flow conditions post 1997.

The entitlement to be secured for the proposed project, which is likely to be a fraction of the SECV share, needs to take this into account so that additional water does not need to be frequently sought from other sources.

The most likely sources of water potentially available in case the Dual Gas's entitlement is insufficient would be either the water market or Gippsland Water. Dual Gas could get into the water market and buy water off:

1) the currently unallocated share of Blue Rock Lake (inflows and volume in storage) if the Government places some of this share on the market,
2) any regulated user, or
3) any unregulated user located upstream of Lake Narracan where the abstraction point for the raw water is likely to be.

Alternatively, Gippsland Water could be approached for a temporary supplement.

4. Assessment of Potential Environmental Impacts

The extra water usage during operation of the proposed power station, being 2 GL/yr with an even monthly distribution, will have a small impact on current river flows. As Table 1 indicates, 2 GL/yr represents about 0.5% of the outflows from the system with full uptake of licence volumes. It is likely that the outflow from the Latrobe River System into the Gippsland Lakes will reduce slightly as a result of increased diversion. This could make it more difficult to achieve the environmental flows recommended by the WGCMA in downstream river reaches, and could potentially have an impact on the water quality in the Gippsland Lakes. However, the proposed diversion does not impact on the ability to provide passing flows set by law for various points on the river.

Compliance with the currently legally enforced environmental flow requirements for the Latrobe River, described in Southern Rural Water's Bulk Entitlement conversion order (Appendix B), will not be affected. These passing flow requirements need to be satisfied prior to allocating any water to users in the catchment. Thus, the use of the entirety or part of SECV's allocated water would not have a detrimental effect on compliance with any legal requirements to provide environmental passing flows.

It is understood that the Dual Gas Demonstration Project will use 70% less water per unit of output compared to the existing brown coal fired power stations. It is possible that the proposed power station displaces other less water efficient power stations in Latrobe Valley under a future carbon constraint environment. This would lead to less water being required per unit of power produced. However, it is unclear whether this would lead to reduced water usage overall as power companies may still require the use of their full entitlement or could prefer to sell their surplus entitlement to another consumptive user.

5. Conclusion

Dual Gas has been provisionally provided a 2GL/yr water allocation from Blue Rock Dam at 95% reliability for their operations. This allocation is to be supplied from the State Electricity Commission Victoria (SECV) unused entitlement. During the construction phase, the water requirement has been estimated at 20 ML/yr. This volume during construction is negligible in relation to both existing entitlements in the Latrobe Valley and river flows. The supply of this water will likely need to be arranged with Gippsland Water or other power stations if the proposed allocation is not in place before the onset of construction.

It has been estimated in recent studies (SKM, 2008) that highly reliable (>99% annual reliability) supply from the SECV's share is approximately 19 GL/yr under a repeat of historical conditions, but only around 11 GL/yr under ongoing low flow conditions post 1997. The entitlement to be secured for the project, which is likely to be a fraction of the SECV share, needs to take into account likely future reductions in water availability due to climate change.

The additional 2GL/yr of diversion by Dual Gas will result in a small reduction in the flows currently available to the environment (Latrobe River downstream of Lake Narracan and Gippsland Lakes). However, compliance with the currently legally enforced environmental flow requirements for the Latrobe River, described in Southern Rural Water's Bulk Entitlement conversion order, will not be affected. As these minimum passing flow requirements need to be satisfied prior to allocating any water to users in the catchment, their compliance will not be influenced by any future diversions for the proposed project.

6. References

DSE. (2006). *Central Region Sustainable Water Strategy.*

DSE. (2009, June 16). *Our Water, Our Future - Allocation and Trading - Bulk Entitlements*. Retrieved 7 6, 2009, from Our Water, Our Future: http://www.ourwater.vic.gov.au/allocation/water_allocation_framework/bulk_entitlements

Gippsland Water. (2007). *Water Supply Demand Strategy, "Sustaining water supply in the Gippsland"*.

SKM. (2008). *Latrobe Model Update 2008.*

Appendix A Bulk Entitlement Conversion Order for the SECV

WATER ACT 1989

Bulk Entitlement (Yallourn Energy Ltd for SECV) Conversion Order 1996

I, Charles Geoffrey Coleman, Minister administering the **Water Act 1989**, make the following Order:-

1. CITATION

This Order may be cited as the Bulk Entitlement (Yallourn Energy Ltd for SECV) Conversion Order 1996.

2. EMPOWERING PROVISIONS

This Order is made under sections 43 and 47 of the **Water Act 1989**.

3. COMMENCEMENT

This Order comes into operation on the day on which it is published in the Government Gazette.

4. DEFINITIONS

In this Order -

"Act" means the **Water Act 1989**;

"AHD" means the Australian Height Datum

"Authority" means Yallourn Energy Limited (ACN 065 325 224) (a generation company within the meaning of the Electricity Industry Act 1993);

"capacity share" means a water entitlement which is expressed as a percentage share of all or any of the following depending on the context in which the expression is used -

(a) storage capacity; and

(b) inflows to the storage; and

(c) storage and transmission losses; and

(d) storage release capacity; and

(e) unregulated flow; and

(f) water carrier capacity;

"entitlement holder" means a person holding a bulk entitlement under the Act;

"Headworks Storages" means the water supply works of Blue Rock Dam, Narracan Dam and Yallourn Weir;

"Headworks System" means -

(a) Headworks Storages; and

(b) the System Waterway;

"Internal Spill" means the redistribution of inflow shares which occurs where an Authority's share of inflow is in excess of the volume required to fill its share of storage capacity;

"Latrobe Basin Water Accounts" means an annual report, required by the Minister, on compliance by entitlement holders and licensees, respectively, in the Latrobe Basin, with the terms of their bulk entitlements or licences;

"Licence" means any licence granted under Part 4 of the Act;

"other Authority" means an Authority other than the Authority or any other person holding a bulk entitlement granted under Division 1 or 3 of Part 4 of the Act;

"passing flow" means an amount of flow referred to in the Bulk Entitlement (Latrobe - Southern Rural) Conversion Order 1996 which the Storage Operator is obliged to pass at nominated points in the System Waterway;

"regulated release" means any release from Blue Rock Reservoir or Lake Narracan excluding releases made by the Storage Operator to -

(a) provide passing flows; or

(b) pass floodwaters; or

(c) pass flows which cannot be stored; or

(d) secure the safety of the Headworks Storages under emergency situations;

"**reservoir entitlement holders**" means all Authorities holding a bulk entitlement in respect of Blue Rock Reservoir at the relevant time;

"**Resource Manager**" means any person appointed by the Minister to do all or any of the following -

(a) prepare the Latrobe Basin Water Accounts; and

(b) monitor whether entitlement holders in the Latrobe Basin comply with the conditions of their bulk entitlements; and

(c) investigate and mediate disputes between entitlement holders in the Latrobe Basin; and

(d) investigate and deal with significant unauthorised uses of water in the Latrobe Basin; and

(e) supervise the qualification of any rights to water made by the Minister during periods of declared water shortage under section 13 of the Act.

"**river regulation costs**" means those costs attributed to the accounting and operating arrangements, established under the Bulk Entitlement (Latrobe - Southern Rural) Conversion Order 1996, to manage the sharing of unregulated flow;

"**source costs**" means the total annual cost to -

(a) operate, maintain and administer the Headworks System; and

(b) make releases from the Headworks System (excluding the river regulation costs); and

(c) meet the financial charges associated with any new or enhancement works undertaken on the Headworks Storages; and

(d) make an appropriate allowance for depreciation of works associated with the Headworks System, except Lake Narracan and Yallourn Weir, using the deprival value approach, or such other depreciation methodology adopted by the Victorian Department of Treasury and Finance to apply to Authorities; and

(e) manage the catchment for water supply purposes to protect the quality of water diverted to, and stored in, the

Headworks System; and

(f) manage the stream gauging stations necessary to operate the Headworks System; and

(g) implement the program established under the Bulk Entitlement (Latrobe - Southern Rural) Conversion Order 1996, to manage the environmental effects of the Headworks System;

"Storage Operator" means any person appointed by the Minister to operate the Headworks System, to manage or measure the flow into the headworks system or System Waterway, or to do all or any of them;

"System Waterway" means the Tanjil River between Blue Rock Reservoir and the Latrobe River, and the Latrobe River downstream of its confluence with the Tanjil River, including the pools formed by, and immediately upstream of, the Blue Rock and Narracan Dams and Yallourn Weir;

"unregulated flow" means any flows in the waterway which cannot be attributed to a regulated release;

"year" means the 12 months next following 1 July.

5. CONVERSION TO BULK ENTITLEMENTS

Only that part of the Authority's entitlement to water from the System Waterway, to provide for the future electricity generation requirements of the SECV or other purposes determined by the SECV, is converted to a bulk entitlement on the conditions set out in this Order.

6. BULK ENTITLEMENT

6.1 The Authority may take the share of flow from the waterway to meet its requirements up to an annual total of 25 000 ML.

6.2 The total annual amount of regulated releases from the Authority's share of Blue Rock Reservoir must not exceed 12 000 ML.

6.3 Subject to section 46 of the Act, this bulk entitlement may be transferred -

(a) temporarily or permanently;

(b) in whole or in part;

(c) for any purpose, including an in-stream use of water.

6.4 The Minister may vary the maximum amount of diversion or regulated release specified under sub-clauses 6.1 and 6.2 respectively for the purpose of making any transfer of this bulk entitlement authorised under section 46 of the Act .

7. SHARE OF CAPACITY

The Authority is entitled to -

(a) a 10.43% share of the total storage capacity of Blue Rock Reservoir, where the total storage capacity is 208 200 ML at a full supply level of 140.00 metres AHD; and

(b) a 20.86% share of the total storage capacity of Lake Narracan, where the total storage capacity is 8000 ML at a full supply level of 47.7 metres AHD; and

(c) all water stored in its share of the storages specified in this sub-clause less a share of losses. Losses are to be assessed as specified in Schedule 1.

8. SHARE OF FLOW

8.1 The Authority may -

(a) after the passing flows requirements have been met, store 10.43% of all the inflow into Blue Rock Reservoir from the catchment up to that amount required to fill its share of storage capacity;

(b) after the passing flows requirements have been met, store 15.61% of unregulated inflow into Lake Narracan to fill its share of storage capacity;

(c) store a greater proportion of the inflow where part of that inflow is assessed by the Storage Operator, as specified in Schedule 1, as an internal spill;

8.2 The Authority must not store as part of its bulk entitlement in Blue Rock Reservoir or Lake Narracan any flow into the storage -

(a) which is specified as the passing flow by the Storage Operator; or

(b) which is being transferred by the holder of any other bulk entitlement; or

(c) any flow into the storage when the Authority's share of the storage is full.

9. REQUIREMENTS TO TAKE WATER

9.1 If the Authority proposes to take water under this entitlement, it must first -

(a) propose to the Minister details of the proposed location and the amount of the extraction; and

(b) propose to the Minister an allowance for any losses and gains if the proposed point of extraction is from a location other than the pool formed by Yallourn Weir; and

(c) propose to the Minister details of any proposed amendment to the Authority's metering program approved under subclause 11.3; and

(d) ascertain and provide the Minister with any operational requirements of the Resource Manager or the Storage Operator.

9.2 The Minister may -

(a) approve the Authority's proposal under sub-clause 9.1; or

(b) require the Authority to amend any aspect of the proposal.

9.3 The Authority must -

(a) advise the Resource Manager in writing within 14 days of any proposal approved by the Minister under sub-clause 9.2; and

(b) provide the Resource Manager with such information concerning the proposed diversion as the Resource Manager may, from time to time, require.

10. RELEASES

10.1 Subject to sub-clause 10.2 the capacity of the outlet works of the reservoir is to be shared in proportion to inflow shares between the reservoir entitlement holders.

10.2 The Authority, after consultation with any other Authorities holding an inflow share to Blue Rock Reservoir, may, within twelve months of the date of this Order, and then from time to time, propose to the Minister an alternate means to ensure a fair and reasonable means of sharing the capacity of the outlet works of the reservoir.

10.3 The Minister must -

(a) approve all or any means proposed under sub-clause 10.2 where there is agreement to the proposal by all other Authorities holding an inflow share; or

(b) where all other Authorities cannot agree, refer the proposal to an independent expert established under sub-clause 18.2 for determination in accordance with clause 18.

11. SUPPLY OF WATER

11.1 The Authority and the Storage Operator must endeavour to agree on operational arrangements to allow the Storage Operator to borrow storage capacity in Lake Narracan for operational purposes.

11.2 If the Authority and the Storage Operator have not reached agreement under sub-clause 11.1 within twelve months of the date of this Order either party may give written notice to the other party requiring the matter to be determined in accordance with clause 19.

12. METERING PROGRAM

12.1 The Authority must propose to the Minister a metering program as part of any proposal approved under clause 9 to take water under this bulk entitlement.

12.2 The metering program prepared under sub-clause 12.1 must include details of any agreement between the Authority and any other person for measuring and calculating inflows to storages or water taken.

12.3 The Minister may -

(a) approve the program proposed under sub-clause 12.1; or

(b) require the Authority to amend the proposed program; and

(c) require the Authority -

(i) to review the program approved by the Minister if, in the Minister's opinion, it is, at any time, no longer appropriate;

and

(ii) to propose an amended program to the Minister.

12.4 The Authority must, at its cost -

(a) implement the approved metering program; and

(b) operate and maintain metering equipment and associated measurement structures in good condition and ensure that metering equipment is periodically re-calibrated, in accordance with any guidelines issued by the Minister; and

(c) keep a record of all work undertaken under paragraph 12.4(b).

13. REPORTING REQUIREMENTS

13.1 The Minister may require the Authority to report on all or any of the following matters, as provided in this clause:

(a) any water taken under this entitlement approved under sub-clause 9.2;

(b) the implementation of programs approved under sub-clause 12.3;

(c) any temporary or permanent transfer of all or part of this bulk entitlement;

(d) any bulk entitlement or licence in respect of the waterway temporarily or permanently transferred to the Authority;

(e) any amendment to this bulk entitlement;

(f) any failure by the Authority to comply with any provision of this bulk entitlement;

(g) any existing or anticipated difficulties experienced by the Authority in complying with this bulk entitlement and any remedial action taken or proposed by the Authority.

13.2 The Minister may require the Authority to report on all or any of the matters set out in sub-clause 13.1 -

(a) in writing or in such electronic form as may be agreed between the Authority and the Minister; and

(b) within 14 days of receiving the Minister's written request or such longer period as the Minister may determine.

13.3 The Authority must, for the period of the preceding year, report, by 1 August in any year, to the Minister on each of the matters set out in sub-clause 13.1.

13.4 The Resource Manager may require the Authority to report from time to time, on all or any of the matters set out in sub-clause 13.1.

13.5 Any report under sub-clause 13.4 must be made -

(a) in such form as may be agreed between the Authority and the person to whom the report is made; and

(b) unless the Authority and that person agree otherwise, within 14 days of the Authority receiving a request for a report on any matter set out in sub-clause 13.1.

14. WATER RESOURCE MANAGEMENT COSTS

14.1 Subject to sub-clause 16.1, the Authority must pay the Resource Manager a proportion of the costs incurred by the Resource Manager to -

(a) prepare the Latrobe Basin Water Accounts; and

(b) monitor whether entitlement holders in the Latrobe Basin comply with the conditions of their bulk entitlements; and

(c) investigate and mediate disputes between entitlement holders in the Latrobe Basin; and

(d) investigate and deal with significant unauthorised uses of water in the Latrobe Basin; and

(e) supervise the qualification of any rights to water made by the Minister during periods of declared water shortage under section 13 of the Act.

14.2 The proportion of the costs referred to in sub-clause 14.1 will be as determined under sub-clause 16.5.

15. STORAGE OPERATOR COSTS

15.1 Subject to sub-clause 16.1 the Authority must pay the Storage Operator an annual source charge which will be determined according to sub-clause

15.2.

15.2 The Authority must pay the Storage Operator -

(a) a percentage of the annual source charges for Lake Narracan and Yallourn Weir as follows -

$$C_s = \$ [0.2086 \times S \times (1+m)] + [0.1561 \times r \times (1+m)]$$

and

(b) a percentage of the annual source charge for Blue Rock Reservoir as follows -

$$C_s = \$ 0.1043 \times S \times (1+m)$$

where -

C_s = the annual source charge.

S = the estimated source costs for the year for which charges are prepared.

r = the estimated river regulation costs for the year for which charges are prepared.

m = the business margin set at 10% at the date of the Order. Any variation to this rate is to be mutually agreed as per sub-clause 17(a).

15.3 The annual source charge must be paid by the Authority each year whether or not water has been taken from the storages by the Authority in that year.

16. DUTY TO KEEP ACCOUNTS AND FIX PROPORTIONS

16.1 The Authority is not obliged to make any payment to -

(a) the Resource Manager under clause 14; or

(b) the Storage Operator under clause 15 -

unless the person to whom the payment is payable chooses to comply with the provisions of this clause relevant to those payments.

16.2 Separate accounts of all costs and payments must be kept -

(a) by the Resource Manager in respect to clause 14; and

(b) the Storage Operator in respect to clause 15.

16.3 The Water Authority responsible for the Headworks Storages must consult with the Authority on any proposal to undertake new or enhancement works on a Headworks Storage, providing reasonable detail and the need for those works, prior to undertaking those works.

16.4 The Authority may object to any proposal referred to in sub-clause 16.3 and may give written notice to the other party requiring the matter to be determined by referral to an independent expert in accordance with clause 19.

16.5 The Resource Manager must, by 1 March in any year, provide an estimate, in respect of the ensuing year, of a fair and reasonable proportion of the costs referred to in sub-clause 14.1.

16.6 The Storage Operator must, by 1 March in any year, in conjunction with the Water Authority responsible for the Headworks Storages, provide the Authority with an estimate of the annual source charge referred to in sub-clause 15.2, for the ensuring year.

16.7 Accounts required to be kept under this clause must be made available for inspection by the Authority upon request.

17. DUTY TO MAKE PAYMENTS

Any amount payable by the Authority under clauses 14 and 15 -

(a) is to be based on the actual expenditure for the period specified in paragraph 17(b) and include any adjustment from a previous period to reflect the actual cost of the work; and

(b) unless the Authority and the person to whom the amount is payable agree otherwise -

  (i) must be paid quarterly in arrears, within 28 days of the Authority receiving an invoice for amounts payable under clause 14; and

  (ii) must be paid monthly in arrears, within 28 days of the Authority receiving an invoice for amounts payable under clause 15.

18. DATA

18.1 The Minister will use the Minister's best endeavours to ensure that all hydrological and other data required by the Authority to comply with this bulk entitlement are made available to the Authority, free of charge.

18.2 The Authority must make available data collected for the purpose of the metering program and reporting under sub-clauses 12.1 and 13.1 to any person, subject to the person paying any fair and reasonable access fee imposed by the Authority, to cover the costs of making the data available.

19. DISPUTE RESOLUTION

19.1 If any difference or dispute arises between the Authority, the Minister and, with his or her consent, the Resource Manager (the "parties") concerning the interpretation or application of this Order, which is not resolved within 14 days of it arising, any party may give written notice to the others requiring the matter to be determined by an independent expert, if it is not otherwise resolved, within 14 days of that notice.

19.2 The independent expert will be either -

(a) a person agreed on by the parties to the difference or dispute; or

(b) if those parties cannot agree, a person nominated by the President of the Institute of Arbitrators Australia.

19.3 The independent expert must reach a conclusion on the matter within 30 days of it being referred, but has power to extend the period for reaching a conclusion on the matter by a further 30 days.

19.4 The independent expert must send a copy of the conclusion and its supporting reasons to each party to the difference or dispute.

19.5 (a) In any difference or dispute to which the Minister is a party, the independent expert must express the conclusion as a recommendation.

(b) the Minister must consider any recommendation made under paragraph 19.5(a) before deciding to give a direction under section 307 or to take any other action under the Act in relation to the difference or dispute.

19.6 In any difference or dispute to which the Minister is not a party, any conclusion by an independent expert is final and binding on the parties.

19.7 The apportionment of the costs of and incidental to every reference, including the costs of the independent expert, shall be at the discretion of the independent expert.

Signed:

Geoff Coleman, Minister administering the **Water Act 1989**

Dated: 25-3-96

Note: An explanatory note that accompanies this Order is available from the Water Bureau, Department of Conservation and Natural Resources.

Schedule 1

Evaporation Losses and Internal Spills

1. Evaporation Losses

Evaporation losses from -

(a) Lake Narracan are calculated using the formula

$$e = A \times E \times 0.01 \times (s1/s)$$

(b) the Blue Rock Reservoir are calculated using the formula

$$e = A \times E \times 0.01 \times (s1/s)$$

where
- e - evaporation loss in ML
- s - volume of water in ML in either Lake Narracan or Blue Rock Reservoir as appropriate
- A - surface area in hectares corresponding to s
- E - pan evaporation in mm
- s1 - volume of water in ML in the Authority's share of Lake Narracan or Blue Rock Reservoir as appropriate

2. Internal Spills

The amount of internal spill cannot exceed a volume equal to the amount by which the other entitlement holder's storage is below its full share. Any internal spill is to be redistributed in proportion to the inflow shares of those Authorities whose shares of storage capacity are not full.

3. Storage Accounts

The storage accounts maintained by the Storage Operator will be adjusted for -

(i) the share of inflow apportioned to the Authority;

(ii) any internal spill;

(iii) any release directed by the Authority to meet its water supply requirements including any allowances for in-transit losses; and

(iv) any allowances for the Authority's share of evaporation losses or seepage losses from storage.

Appendix B Bulk Entitlement Conversion Order for Southern Rural Water

WATER ACT 1989

Bulk Entitlement (Latrobe - Southern Rural) Conversion Order 1996

I, Charles Geoffrey Coleman, Minister administering the **Water Act 1989**, make the following Order:-

1. CITATION

This Order may be cited as the Bulk Entitlement (Latrobe - Southern Rural) Conversion Order 1996.

2. EMPOWERING PROVISIONS

This Order is made under sections 43 and 47 of the **Water Act 1989.**

3. COMMENCEMENT

This Order comes into operation on the day on which it is published in the Government Gazette.

4. DEFINITIONS

In this Order -

"Act" means the **Water Act 1989;**

"AHD" means the Australian Height Datum

"Authority" means the Gippsland and Southern Rural Water Authority;

"capacity share" means a water entitlement which is expressed as a percentage share of all or any of the following depending on the context in which the expression is used -

(a) storage capacity; and

(b) inflows to the storage; and

(c) storage and transmission losses; and

(d) storage release capacity; and

(e) unregulated flow; and

(f) water carrier capacity;

"entitlement holder" means a person holding a bulk entitlement under the Act;

"exchange rate" means the rate, determined by the Minister, at which the security of supply varies inversely to the annual entitlement;

"Headworks Storages" means the water supply works of Blue Rock Dam, Lake Narracan and Yallourn Weir;

"Headworks System" means -

(a) Headworks Storages; and

(b) the System Waterway;

"Internal Spill" means the redistribution of inflow shares which occurs where an Authority's share of inflow is in excess of the volume required to fill its share of storage capacity;

"Latrobe Basin Water Accounts" means an annual report, required by the Minister, on compliance by entitlement holders and licensees, respectively, in the Latrobe Basin, with the terms of their bulk entitlements or licences;

"Licence" means any licence granted under Part 4 of the Act;

"modified natural flow" means the sum of the flows of the Tanjil River at Tanjil South (gauging station number 226216) and the unregulated flows above the respective specified passing flow point;

"other Authority" means an Authority other than the Authority or any other person holding a bulk entitlement granted under Division 1 of Part 4 of the Act;

"passing flows" means the flows referred to in clause 11;

"primary entitlement" means an entitlement or commitment referred to in clause 7;

"regulated release" means any release from Blue Rock Reservoir or Lake Narracan excluding releases made by the Storage Operator to -

(a) provide passing flows; or

(b) pass floodwaters; or

(c) pass flows which cannot be stored; or

(d) secure the safety of the Headworks Storages under emergency situations;

"**Resource Manager**" means any person appointed by the Minister to do all or any of the following -

(a) prepare the Latrobe Basin Water Accounts; and

(b) monitor whether entitlement holders in the Latrobe Basin comply with the conditions of their bulk entitlements; and

(c) investigate and mediate disputes between entitlement holders in the Latrobe Basin; and

(d) investigate and deal with significant unauthorised uses of water in the Latrobe Basin; and

(e) supervise the qualification of any rights to water made by the Minister during periods of declared water shortage under section 13 of the Act.

"**river regulation costs**" means those costs attributed to the accounting and operating arrangements referred to in sub-clause 13.2

"**Rosedale Gauging Station**" means the stream gauging station, number 226228, located on the main stream of the Latrobe River at Rosedale;

"**security of supply**" [1] means the statistical probability of being able to supply a given volume of water in a year;

"**source costs**" means the total annual cost to -

(a) operate, maintain and administer the Headworks System; and

(b) make releases from the Headworks System (excluding the river regulation costs); and

(c) meet the financial charges associated with any new or enhancement works undertaken on the Headworks Storages; and

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[1] See Explanatory Note on Schedule 2 accompanying the Order

(d) make an appropriate allowance for depreciation of works associated with the Headworks System, except Lake Narracan and Yallourn Weir, using the deprival value approach, or such other depreciation methodology adopted by the Victorian Department of Treasury and Finance to apply to Authorities; and

(e) manage the catchment for water supply purposes to protect the quality of water diverted to, and stored in, the Headworks System; and

(f) manage the stream gauging stations necessary to operate the Headworks System; and

(g) implement the program established under the Bulk Entitlement (Latrobe - Southern Rural) Conversion Order 1995, to manage the environmental effects of the Headworks System;

"Storage Operator" means any person appointed by the Minister to operate the Headworks System, to manage or measure the flow into the headworks system or System Waterway, to keep, and report on, the water accounts of the capacity shares, or to do all or any of them;

"Swing Bridge (Sale) Gauging Station" means the stream gauging station, number 226027, located on the Latrobe River;

"System Waterway" means the Tanjil River between Blue Rock Reservoir and the Latrobe River, and the Latrobe River downstream of its confluence with the Tanjil River, including the pools formed by, and immediately upstream of, the Blue Rock and Narracan Dams and Yallourn Weir;

"Thoms Bridge Gauging Station" means the stream gauging station, number 226005, located on the Latrobe River;

"unregulated flow" means any flows in the System Waterway which cannot be attributed to a regulated release or a discharge from the works of an industrial company or other Authority;

"year" means the 12 months next following 1 July.

5. CONVERSION TO BULK ENTITLEMENTS

All of the Authority's entitlement to water from the System Waterway is converted to a bulk entitlement on the conditions set out in this Order.

6. BULK ENTITLEMENT

6.1 The Authority may take the share of flow from the System Waterway to meet its requirements and to supply primary entitlements up to an average annual total of 13 400 ML over any period of two consecutive years.

6.2 Regulated releases from the Authority's share of Blue Rock Reservoir must not exceed an average annual total of 3 600 ML over any period of two consecutive years.

7. OBLIGATIONS TO SUPPLY PRIMARY ENTITLEMENTS

Water taken from the System Waterway under this bulk entitlement must be used to supply the licences, described in Schedule 1, in accordance with the allocation procedures and restriction policies referred to in sub-clause 13.4(b) and Schedule 2.

8. TRANSFER OF ENTITLEMENT/ ADJUSTMENT OF SCHEDULES

8.1[2] Subject to section 46 of the Act and clause 8.2, this bulk entitlement may be transferred -

(a) temporarily or permanently;

(b) in whole or in part;

(c) for any purpose, including an in-stream use of water.

8.2 The Minister may, from time to time, alter Schedule 1 to reflect -

(a) any trading between a person holding a licence and another bulk entitlement;

(b) any new licence allocated under section 51, 52 or 57 of the Act;

(c) any trading between persons holding licences;

(d) alterations to the security of any licence included under Schedule 2 in accordance with exchange rates determined by the Minister;

[2] See Explanatory Note accompanying the Order

9. SHARE OF CAPACITY

The Authority is entitled to -

(a) a 2.0% share of the total storage capacity of Blue Rock Reservoir, where the total storage capacity is 208 200 ML at a full supply level of 140.00 metres AHD; and

(b) a 0% share of the total storage capacity of Lake Narracan, where the total storage capacity is 8000 ML at a full supply level of 47.7 metres AHD.

(c) all water stored in its share of the storages specified in this sub-clause less a share of losses. Losses are to be assessed as specified in Schedule 3.

10. SHARE OF FLOW

10.1 The Authority may -

(a) after the passing flows requirements have been met, store 2.0% of all the inflow into Blue Rock Reservoir from the catchment up to that amount required to fill its share of storage capacity;

(b) store a greater proportion of the inflow where part of that inflow is assessed by the Storage Operator, as specified in Schedule 3, as an internal spill;

10.2 The Authority, after allowing for the passing flows requirements at the Thoms Bridge, Rosedale and Swing Bridge Gauging Stations, specified in clause 11, may allow, subject to sub-clause 13.4, those licence holders referred to in Schedule 1 to take from the System Waterway -

(a) a 25.15% share of the unregulated flow, as calculated by the Storage Operator, at the point immediately downstream of Lake Narracan; and

(b) additional unregulated flow above its 25.15% share, at the point immediately downstream of Lake Narracan, subject to the additional flow in excess of the Authority's flow share -

(I) not being used by any other Authority holding an entitlement to that additional flow; and

(ii) being shared with other Authorities holding a share of unregulated flow at this point in proportion to each of the

Authorities' shares of unregulated flow.

10.3 The Authority must not store as part of its bulk entitlement in Blue Rock Reservoir any flow into the storage -

(a) which is specified as the passing flow by the Storage Operator; or

(b) which is being transferred by the holder of any other bulk entitlement; or

(c) when the Authority's share of the storage is full.

11. PASSING FLOW

11.1 The Authority must direct the Storage Operator to provide -

(a) a minimum passing flow in the Tanjil River immediately below the Blue Rock Dam to maintain the flow at the Tanjil South gauging station as specified in Schedule 4, or the natural flow at this location, whichever is the lesser; and

(b) a minimum passing flow below Yallourn Weir to maintain flows in the Latrobe River of a minimum average weekly flow of 350 ML/d over any seven day period, at a daily rate of no less than 300 ML/d, at the Thoms Bridge gauging station, or the modified natural flow at this location, whichever is the lesser; and

(c) to provide, to its best endeavours in the period until 1 July 1999, after which time it must provide, a minimum passing flow below Yallourn Weir to maintain flows in the Latrobe River of a minimum average weekly flow of -

(i) 500 ML/d over any seven day period, at a daily rate of no less than 450 ML/d, at the Rosedale gauging station, or the modified natural flow, whichever is the lesser; and

(ii) 750 ML/d over any seven day period, at a daily estimated rate of no less than 700 ML/d, at the Swing Bridge (Sale) gauging station, or the modified natural flow, whichever is the lesser.

11.2 The Authority must propose to the Minister within three months of the date of this Order a basis under which the flow referred to in sub-clause 11.1(c)(ii) is to be estimated.

11.3 The Authority, after consultation with other entitlement holders from the

System Waterway and the Department of Conservation and Natural Resources, may propose to the Minister a variation to the minimum passing flows as set out in sub-clause 11.1 to either -

(a) reinstate the flow regime in the System Waterway where this has been adversely affected by the -

(I) return flows from other Authorities to the System Waterway and its tributary streams being less than those assumed by the Minister at the commencement of this Order; or

(ii) provision for losses, assessed to be necessary by the Storage Operator, in the release of water from Blue Rock Reservoir or Lake Narracan, being greater than those assumed by the Minister at the commencement of this Order; or

(b) increase operational flexibility in meeting the minimum average passing flow requirements.

11.4 The proposal referred to in sub-clause 11.3(a) must -

(a) demonstrate that -

(I) with respect to paragraph 11.3(a)(I) -

(A) any monthly shortfalls, between the expected return flow contributions, based on recent records, and the assumed return flows, could not be provided from other compensating factors or from borrowing arrangements between the Storage Operator and any other Authority; and

(B) in the period after 1 July 1999, based on the actual records to that date, the return flow contributions are expected to be significantly different in the long term from the return flows assumed at the commencement date of the Order; and

(ii) with respect to paragraph 11.3(a)(ii), under operational experience over a period of not less than 1 year, the actual losses are significantly higher than those assumed at the commencement date of the Order; and

(b) provide an assessment of the effect on the security of supply to other entitlement holders.

11.5 The proposal referred to in sub-clause 11.3(b) must demonstrate that, under operational experience over a period of not less than 1 year, the provision of the average passing flow requirements cannot be met without an unreasonable impact on the security of licence holders.

11.6 The Minister may -

(a) approve or not approve a proposal made under sub-clauses 11.2 or 11.3; or

(b) require the Authority to amend the proposal; and

(c) require the Authority -

(i) to review all or part of any proposal approved by the Minister if, in the Minister's opinion, it is, at any time, no longer fair, reasonable or representative; and

(ii) to propose an amended proposal to the Minister.

11.7 The Authority must -

(a) advise the Resource Manager in writing within 14 days of any proposal approved by the Minister under sub-clause 11.6; and

(b) provide the Resource Manager with such other information concerning the proposed passing flows as the Resource Manager may, from time to time, require.

12. RELEASES

12.1 The Authority must direct the Storage Operator to release water to meet the passing flow requirements in the Tanjil and Latrobe Rivers.

12.2 Subject to sub-clause 12.3 the capacity of the outlet works of Blue Rock Reservoir is to be shared in proportion to inflow shares between the reservoir entitlement holders.

12.3 The Authority, after consultation with any other Authorities holding an inflow share to Blue Rock Reservoir, may, within twelve months of the date of this Order, and then from time to time, propose to the Minister an alternate means to ensure a fair and reasonable means of sharing the capacity of the outlet works of the reservoir.

12.4 The Minister must -

(a) approve all or any means proposed under sub-clause 12.3 where there is agreement to the proposal by all other Authorities holding an inflow share; or

(b) where all other Authorities cannot agree, refer the proposal to an independent expert established under sub-clause 22.2 for determination in accordance with clause 22.

13. SUPPLY OF WATER

13.1 The Authority will direct the Storage Operator to maintain the water level within the pool formed by Yallourn Weir at a height -

(a) no less than 40.35 m AHD, unless agreement is reached with any other Authority holding a bulk entitlement to take water from the pool, to vary this arrangement; and

(b) not exceeding 40.75 m AHD except in the event of extreme flood conditions.

13.2 The Authority and the Storage Operator must endeavour to agree on operational arrangements for the supply of water from the storages mentioned in clause 7.

13.3 If the Authority and the Storage Operator have not reached agreement under sub-clause 13.2 within twelve months of the date of this Order either party may give written notice to the other party requiring the matter to be determined in accordance with clause 22.

13.4 The Authority, after consultation with other Authorities where unregulated flow is shared, must propose to the Minister within three months of the date of this Order -

(a) the water accounting and operating arrangements which govern the Authority's share of water to supply licence holders from the System Waterway; and

(b) the allocation procedures and restriction policies to ensure the Authority's usage through diversions by licence holders is in accordance with clause 6 and Schedule 2.

13.5 The proposal referred to in sub-clause 13.4(a) must include the procedures, to be undertaken by the Storage Operator, to translate the daily projected usage by licence holders from the System Waterway to an equivalent volume at the point below Lake Narracan where the unregulated flow is shared, to establish -

(a) the Authority's use of its inflow share; and

(b) the unused share of inflow that is available for use by other Authorities.

13.6 The Minister may -

(a) approve a proposal made under sub-clause 13.4; or

(b) require the Authority to amend the proposal; and

(c) require the Authority -

(i) to review all or part of any proposal approved by the Minister if, in the Minister's opinion, it is, at any time, no longer fair, reasonable or representative; and

(ii) to propose an amended proposal to the Minister.

13.7 The Authority must -

(a) advise the Resource Manager in writing within 14 days of any proposal approved by the Minister under sub-clause 13.4 and

(b) provide the Resource Manager with such other information concerning the proposed diversion as the Resource Manager may, from time to time, require.

14. ENVIRONMENTAL OBLIGATIONS

14.1 The Authority must propose to the Minister, within 12 months of the date of this Order, a program to manage the environmental effects of the Authority's works to allow water to be taken from the System Waterway, including -

(a) the effects on the bed and banks of the waterway in the vicinity of the Authority's works; and

(b) operational practices to remove silt from works; and

(c) operational practices to manage the water quality in works on the waterway; and

(d) operational rules to control releases from works to the waterway; and

(e) operational rules to manage flood flows through works on the waterway.

14.2 The Minister may -

(a) approve the program proposed under sub-clause 14.1; or

(b) require the Authority to amend the proposed program; and

(c) require the Authority -

(i) to review the program approved by the Minister if, in the Minister's opinion, it is, at any time, no longer appropriate; and

(ii) to propose an amended program to the Minister.

14.3 The Authority must at its cost -

(a) implement the approved program; and

(b) keep a record of -

(i) all work undertaken under paragraph (a); and

(ii) separate accounts of all costs and payments for this work.

14.4 The Authority may recover the costs of implementing the approved program from the Storage Operator.

15. METERING PROGRAM

15.1 The Authority must propose to the Minister within 12 months of the date of this Order a metering program to demonstrate compliance with this bulk entitlement with respect to -

(a) all water taken by the Authority under this bulk entitlement; and

(b) the flow into each or any of the storages mentioned in clause 9; and

(c) the passing flows.

15.2 The metering program prepared under sub-clause 15.1 must include details of any agreement between the Authority and any other person for measuring and calculating instream flows or water taken.

15.3 The Minister may -

(a) approve the program proposed under sub-clause 15.1; or

(b) require the Authority to amend the proposed program; and

(c) require the Authority -

(i) to review the program approved by the Minister if, in the Minister's opinion, it is, at any time, no longer appropriate; and

(ii) to propose an amended program to the Minister.

15.4 The Authority must, at its cost -

(a) implement the approved metering program; and

(b) operate and maintain metering equipment and associated measurement structures in good condition and ensure that metering equipment is periodically re-calibrated, in accordance with any guidelines issued by the Minister; and

(c) keep a record of all work undertaken under paragraph (b).

16. REPORTING REQUIREMENTS

16.1 The Authority may be required to report on all or any of the following matters, as provided in this clause:

(a) the daily flow passing Blue Rock Reservoir, Lake Narracan and Yallourn Weir;

(b) the daily flow passing the Tanjil South, Thoms Bridge and Rosedale gauging stations and the estimated daily flow passing the Swing Bridge (Sale) gauging station;

(c) the estimated daily amount of water taken by Licence holders, listed under Schedule 1, from the System Waterway -

(i) upstream of Yallourn Weir; and

(ii) downstream of Yallourn Weir;

(d) the daily flow into Blue Rock Reservoir and Lake Narracan;

(e) the amount of water in Blue Rock Reservoir and Lake Narracan;

(f) the amount of water in the Authority's share of Blue Rock Reservoir;

(g) the annual amount of water taken by Licence holders, listed under Schedule 1, from the System Waterway -

  (i) upstream of Yallourn Weir; and

  (ii) downstream of Yallourn Weir;

(h) the amount of annual losses debited to the Authority's share of Blue Rock Reservoir;

(i) the annual amount of any internal spill of water from, or to, the Authority's share of storage in Blue Rock Reservoir;

(j) any periods of rationing and the degree of rationing of Licence holders listed under Schedule 1;

(k) the operational performance in meeting the specified passing flow requirements in the period to 1 July, 1999, and any actions taken to overcome failures to meet the passing flow targets;

(l) the implementation of programs approved under sub-clauses 14.2 and 15.3;

(m) any temporary or permanent transfer of all or part of this bulk entitlement;

(n) any bulk entitlement or licence in respect of the System Waterway temporarily or permanently transferred to the Authority;

(o) any amendment to this bulk entitlement;

(p) the annual amount supplied to any group of Licence holders specified by the Minister;

(q) any failure by the Authority to comply with any provision of this bulk entitlement;

(r) any existing or anticipated difficulties experienced by the Authority in complying with this bulk entitlement and any remedial action taken or proposed by the Authority.

16.2 The Minister may require the Authority to report on all or any of the matters set out in sub-clause 16.1 -

(a) in writing or in such electronic form as may be agreed between the Authority and the Minister; and

(b) within 14 days of receiving the Minister's written request or such longer period as the Minister may determine.

16.3 The Authority must, for the period of the preceding year, report in its Annual Report on each of the matters set out in sub-clause 16.1, except -

(a) paragraphs 16.1(a), (b), (c) and (d) of sub-clause 16.1; and

(b) with the approval of the Minister, any particular failure referred to in paragraph (q) of sub-clause 16.1.

16.4 The Resource Manager may require the Authority to report from time to time, on all or any of the matters set out in paragraphs (a) to (r) of sub-clause 16.1.

16.5 Any report under sub-clause 16.4 must be made -

(a) in such form as may be agreed between the Authority and the person to whom the report is made; and

(b) unless the Authority and that person agree otherwise -

(i) within 24 hours of the Authority receiving a request for a report on any matter set out in paragraph (a) to (e) of sub-clause 16.1; or

(ii) within 14 days of the Authority receiving a request for a report on any matter set out in paragraph (f) to (r) of sub-clause 16.1.

17. WATER RESOURCE MANAGEMENT COSTS

17.1 Subject to sub-clause 19.1, the Authority must pay the Resource Manager a proportion of the costs incurred by the Resource Manager to -

(a) prepare the Latrobe Basin Water Accounts; and

(b) monitor whether entitlement holders in the Latrobe Basin comply with the conditions of their bulk entitlements; and

(d) investigate and mediate disputes between entitlement holders in the Latrobe Basin; and

(e) investigate and deal with significant unauthorised uses of water in the Latrobe Basin; and

(f) supervise the qualification of any rights to water made by the Minister during periods of declared water shortage under section 13 of the Act.

17.2 The proportion of the costs referred to in sub-clause 17.1 will be as determined under sub-clause 19.3.

18. STORAGE OPERATOR COSTS

18.1 Subject to sub-clause 19.1 the Authority must pay the Storage Operator an annual source charge which will be determined according to sub-clause 18.2.

18.2 The Authority must pay the Storage Operator -

(a) a percentage of the annual source charges for Lake Narracan and Yallourn Weir as follows -

$$\mathbf{C_s = \$\,[\,0.2515 \times r \times (1+m)]}$$

(b) a percentage of the annual source charge for Blue Rock Reservoir as follows -

$$\mathbf{C_s = \$\,0.02 \times S \times (1+m)}$$

where -

C_s = the annual source charge.

S = the estimated source costs for the year for which charges are prepared.

r = the river regulation costs for the year for which charges are prepared.

m = the business margin set at 10% at the date of the Order. Any variation to this rate is to be mutually agreed as per sub-clause 20(a).

18.3 The charge referred to in sub-clause 18.2 must be paid by the Authority every year regardless of the amount of water diverted from the System

Waterway by Licence holders.

19. DUTY TO KEEP ACCOUNTS AND FIX PROPORTIONS

19.1 The Authority is not obliged to make any payment to -

(a) the Resource Manager under clause 17; or

(b) the Storage Operator under clause 18 -

unless the person to whom the payment is payable chooses to comply with the provisions of this clause relevant to those payments.

19.2 Separate accounts of all costs and payments must be kept -

(a) by the Resource Manager in respect to clause 17; and

(b) the Storage Operator under clause 18.

19.3 The Resource Manager must, by 1 March in any year, provide an estimate, in respect of the ensuing year, of a fair and reasonable proportion of the costs referred to in sub-clause 17.1.

19.4 The Storage Operator must, by 1 March in any year, in conjunction with the Water Authority responsible for the Headworks Storages, provide the Authority with an estimate of the annual source charge referred to in sub-clause 18.2, for the ensuring year.

19.5 Accounts required to be kept under this clause must be made available for inspection by the Authority upon request.

20. DUTY TO MAKE PAYMENTS

Any amount payable by the Authority under clause 17 and 18 -

(a) is to be based on the actual expenditure for the period specified in paragraph (b) and include any adjustment from a previous period to reflect the actual cost of the work; and

(b) unless the Authority and the person to whom the amount is payable agree otherwise -

(i) must be paid quarterly in arrears, within 28 days of the Authority receiving an invoice for amounts payable under clause 17; and

(ii) must be paid monthly in arrears, within 28 days of the Authority receiving an invoice for amounts payable under clause 18.

21. DATA

21.1 The Minister will use the Minister's best endeavours to ensure that all hydrological and other data required by the Authority to comply with this bulk entitlement are made available to the Authority, free of charge.

21.2 The Authority must make available data collected for the purpose of the metering program and reporting under sub-clauses 15.1 and 16.1 to any person, subject to the person paying any fair and reasonable access fee imposed by the Authority, to cover the costs of making the data available.

22. DISPUTE RESOLUTION

22.1 If any difference or dispute arises between the Authority, the Minister and, with their consent, the Resource Manager, the Storage Operator and the Water Authority responsible for Headworks Storages (the "parties") concerning the interpretation or application of this Order, which is not resolved within 14 days of it arising, any party may give written notice to the others requiring the matter to be determined by an independent expert, if it is not otherwise resolved, within 14 days of that notice.

22.2 The independent expert will be either -

(a) a person agreed on by the parties to the difference or dispute; or

(b) if those parties cannot agree, a person nominated by the Minister

22.3 The independent expert must reach a conclusion on the matter within 30 days of it being referred, but has power to extend the period for reaching a conclusion on the matter by a further 30 days.

22.4 The independent expert must send a copy of the conclusion and its supporting reasons to each party to the difference or dispute.

22.5 (a) In any difference or dispute to which the Minister is a party, the independent expert must express the conclusion as a recommendation.

(b) the Minister must consider any recommendation made under paragraph 22.5(a) before deciding to give a direction under section 307 or to take any other action under the Act in relation to the difference or dispute.

22.6 In any difference or dispute to which the Minister is not a party, any conclusion by an independent expert is final and binding on the parties.

22.7 The apportionment of the costs of and incidental to every reference, including the costs of the independent expert, shall be at the discretion of the independent expert.

Signed:

Geoff Coleman, Minister administering the **Water Act 1989**

Dated: 25-3-96

Note: An explanatory note that accompanies this Order is available from the Water Bureau, Department of Conservation and Natural Resources.

Schedule 1

Licences Identified as Primary Entitlements

The following entitlements, as established under Licence are to be supplied, or are to be available for supply subject to the supply arrangements approved under sub-clause 13.4:

1. 683 ML of licensed diversions issued to take and use water from the System Waterway upstream of Yallourn Weir.

2. 10456 ML of licensed diversions issued to take and use water from the System Waterway downstream of Yallourn Weir.

Schedule 2

Security of Primary Entitlements set out in Schedule 1

1. Except as set out in this clause, the Authority must supply the licence entitlements with 97% security.

2. The Minister may, by reference to an appropriate computer model, modify the level of security set out in clause 1, where the Minister is satisfied that either -

   (a) hydrological conditions have changed since May 1995; or

   (b) the estimate of security of supply, based on the water allocation and operating rules applying at the date of this Order has improved.

3. Where the Authority is unable to supply the full primary entitlements listed in Schedule 1, the Authority must allocate the available water pro-rata between primary entitlements.

Schedule 3

Evaporation Losses and Internal Spills

1. Evaporation Losses

Evaporation losses from -

(a) Lake Narracan are calculated using the formula

$$e = A \times E \times 0.01 \times (s1/s)$$

(b) the Blue Rock Reservoir are calculated using the formula

$$e = A \times E \times 0.01 \times (s1/s)$$

where
e - evaporation loss in ML
s - volume of water in either Lake Narracan or Blue Rock Reservoir as appropriate
A - surface area in hectares corresponding to s
E - pan evaporation in mm
s1 - volume of water in the Authority's share of Lake Narracan or Blue Rock Reservoir as appropriate

2. Internal Spills

The amount of internal spill cannot exceed a volume equal to the amount by which the other entitlement holder's storage is below its full share. Any internal spill is to be redistributed in proportion to the inflow shares of those Authorities whose shares of storage capacity are not full.

3. Storage Accounts

The storage accounts maintained by the Storage Operator will be adjusted for -

(i) the share of inflow apportioned to the Authority;

(ii) any internal spill;

(iii) any release directed by the Authority to meet its water supply requirements including any allowances for in-transit losses; and

(iv) any allowance for the Authority's share of evaporation losses or seepage losses from storage.

Schedule 4

Passing Flows for the Tanjil River at Tanjil South

Month	Minimum Passing Flow ML/d
January	90
February	90
March	90
April	90
May	100
June	100
July	100
August	150
September	150
October	150
November	150
December	100

Appendix C Air Quality Assessment

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HRL DEVELOPMENTS

AIR QUALITY MODELLING ASSESSMENT – 600MW DUAL GAS DEMONSTRATION PROJECT IN LATROBE VALLEY

Report No: HLC/2009/430/R4
June 2010
CONFIDENTIAL - CLIENT USE ONLY

By

David Thornton

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EXECUTIVE SUMMARY

Dual Gas Pty. Ltd. (DGPL) is proposing a 600MW power station to demonstrate Integrated Drying Gasification Combined Cycle (IDGCC) technology at commercial scale, to be located within the Energy Brix Australia Corporation (EBAC) site in the Latrobe Valley, Victoria. The Project is to comprise two Integrated Drying and Gasification units feeding two Combined Cycle Gas Turbines.

A dispersion modelling assessment of air quality effects from point source emitters has been undertaken to determine cumulative ground level concentrations of nitrogen dioxide (NO_2), and sulfur dioxide (SO_2) resulting from the proposed power plant and with other Latrobe Valley sources utilising the advanced non-steady state model CALPUFF V 6.262.

Modelled 99.9th percentile 1-hour ground level concentrations of NO_2 and SO_2 as predicted by CALPUFF are below the State Environment Protection Policy 1-hour Design Ground Level Concentration (DGLC) of 0.10ppm and 0.17ppm respectively.

In conjunction with other point sources within the Latrobe Valley, the highest 99.9th percentile 1-hour average modelled value for NO_2 is 0.05 ppm and occurs approximately 2-km south south-west of the proposed power station. The highest 99.9th percentile 1-hour average modelled value for SO_2 in conjunction with other Latrobe Valley sources is 0.15 ppm and occurs approximately 13-km east of the proposed power plant. 99.9th percentile 1-hour average modelled concentration values at various discrete receptor locations, including present-day Latrobe Valley Air Monitoring Network (LVAMN) stations, are also below the design criteria for the modelled contaminants.

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1. INTRODUCTION

Dual Gas Pty. Ltd. (DGPL) is proposing to build, own and operate a Dual Gas Demonstration Project (DGDP) located in the Latrobe Valley, Victoria. The open-ended Latrobe Valley extends approximately 130km inland from the east coast and is bordered by the Great Dividing Range (maximum peaks approximately 2000m) to the north and the Strzelecki Range to the south (peaks near 700m). Located approximately 120km southeast of Melbourne, the valley is typically 15km wide and narrows to approximately 8km in its western section. DGPL proposes a 600MW power station consisting of two Combined Cycle Gas Turbine (CCGT) units and two Integrated Drying and Gasification plants. Approximately 4km of 500kV transmission lines are to be connected to the Hazelwood Terminal Station.

The proposed Dual Gas Demonstration Project (DGDP) site is located within the existing Energy Brix Australia Corporation (EBAC) complex, south of the township of Morwell (see Appendix A). The primary fuel of the DGDP is synthesis gas, ('syngas'), to be generated from brown coal, with natural gas as start-up and make-up fuel. DGPL estimates the compositions of the gaseous fuels to be:

- Syngas - variable composition; e.g., H_2O 13%, N_2 36%, H_2 18%, CO 18%, CO_2 11%, CH_4 4% (25 bar, 260ºC, %volume). Note the sulfur content of the syngas is very small; i.e., in Latrobe Valley coals the sulfur is typically 0.3% (dry basis) with some of this captured in fly ash. Sulfur in the coal is converted to SO_2 during combustion.
- Natural Gas - variable composition, but primarily methane (CH_4) and ethane (C_2H_6); in Victoria, comprising approximately 90% and 5% by volume respectively.

Coal for the syngas generation will be via the use of Morwell coal and transported via conveyor to the EBAC site. Air quality effects from mining operations are not included in this modelling assessment.

The initial operation phase is planned for 2012 to 2013. During this first stage, approximately half of the generation capacity will be operated on syngas (when the gasifier is available) and the remainder on natural gas (when it is economic to operate). The second gasifier is planned to be installed after acceptable performance is demonstrated for the first gasifier, and currently planned to commence operation in early 2015. After completion of the second gasifier, the capacity factor for syngas operation is planned to be approximately 85% and natural gas approximately 10% (with 5% down-time) (SKM, 2009).

The key air pollutants from the combustion of syngas are expected to be nitrogen dioxide (NO_2) and sulfur dioxide (SO_2). For natural gas combusted in burners and gas turbines the key air pollutant with respect to ambient air quality is NO_2, with SO_2 emissions expected to be less significant. An air quality modelling assessment has been undertaken to determine cumulative ground level concentrations of NO_2 and SO_2 resulting from point source emissions of the proposed 600MW DGDP power plant located south of Morwell in conjunction with other Latrobe Valley sources. DGPL intends to submit a Works Approval Application for the proposed Project to EPA Victoria. Results from this air quality modelling assessment will form part of the submission.

2. AIR QUALITY MODELLING

Modelling of NOx and SO_2 from the proposed 600MW power plant has been carried out in conjunction with other Latrobe Valley sources (Energy Brix, Hazelwood, Yallourn, Loy Yang A & B, Jeeralang A & B power stations, and Australian Paper) utilising the advanced non-steady state model CALPUFF V 6.262.

CALPUFF is a multi-layer, multispecies non-steady-state Gaussian puff dispersion model which is able to simulate the effects of time and space varying meteorological conditions. This enables the model to account for a variety of effects including terrain, plume fumigation and low wind speed dispersion.

CALPUFF model selected options: site specific wind profile coefficients; stack-tip downwash selected; partial plume penetration mode; partial plume terrain adjustment; turbulence characteristics determined from micrometeorology measured by the Thoms Bridge acoustic sounder (10m, 100m 200m 300m, 400m, 500m, 750m and 1000m).

2.1 Modelled scenarios

Modelling of NOx and SO_2 from the proposed 600MW power plant has been carried out in conjunction with other Latrobe Valley sources. That is, two scenarios have been modelled:

1) NOx from the proposed 600MW power plant plus other Latrobe Valley sources for a 1-year simulation period and 2) SO_2 from the proposed 600MW power plant plus other Latrobe Valley sources for a 1-year simulation period. In addition, predicted 1-hour ground level concentrations of NO_2 resulting from 100% natural gas operation of the proposed 600MW Dual Gas Demonstration Project has also been assessed. Discrete receptors were included at various locations, including the present-day Latrobe Valley Air Monitoring Network (LVAMN) stations located at Moe, Traralgon, Rosedale South and Jeeralang Hill (Figure 1). Four homesteads to the east and southeast of the proposed power plant have been identified as sensitive receptors (SKM, 2009) and also included in the modelling. CALPUFF modelling has covered a 51km x 31km region of the Latrobe Valley at a spatial resolution of 1km with the SW corner located at 431.4kmE and 5751.4kmN, and utilising a CALMET generated meteorological data file developed from 1991 meteorology as discussed in Section 4.

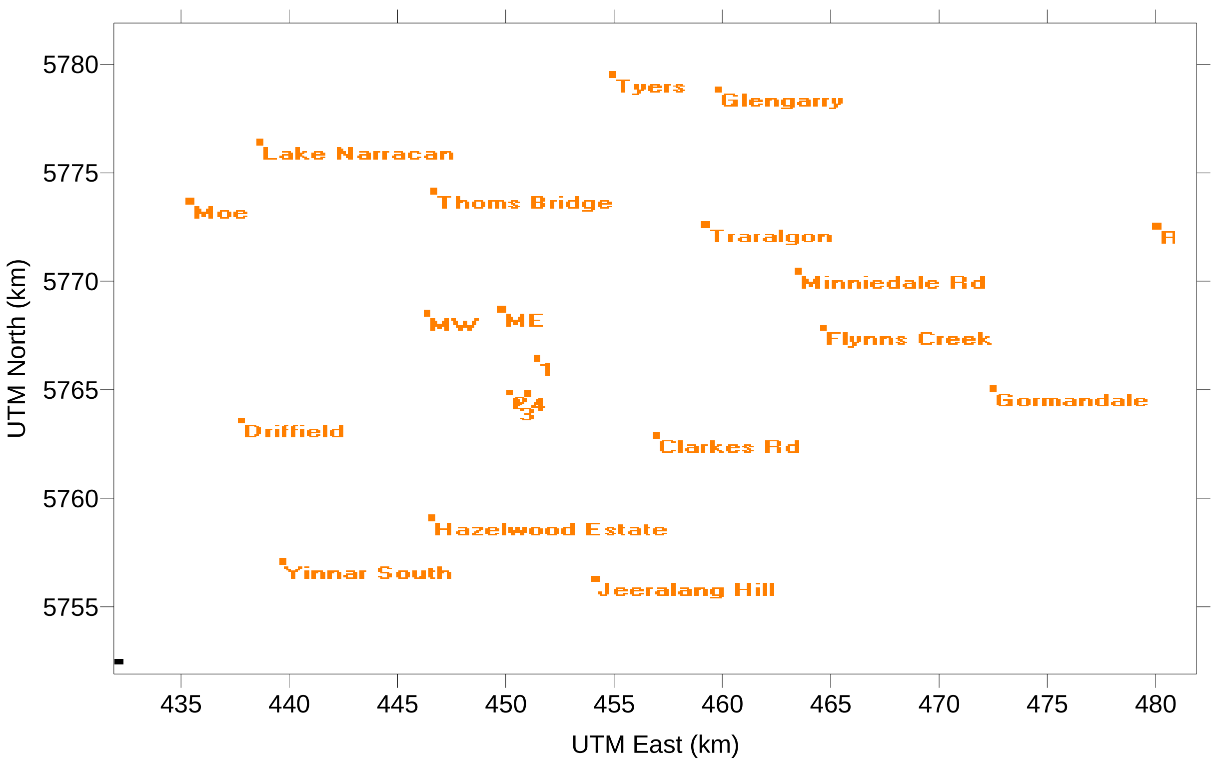

Figure 1. Discrete receptor locations (x 21) included in the modelling assessment. MW = Morwell West; ME = Morwell East; R = Rosedale South; 1,2,3,4 = Homesteads.

3. EMISSIONS DATA

3.1 Dual Gas Demonstration Project

NOx and SO_2 emissions (Appendix B) for the proposed 600MW DGDP reflect the two extremes of operation at full output: 1) 2 x gasifier operation providing full capacity for 2 x gas turbines with maximum supplementary duct firing on natural gas; 2) 2 x gas turbine operation at full output with maximum supplementary duct firing on natural gas. SO_2 emissions are based on highest expected sulfur content of coal and emissions for either Morwell or Yallourn North Extension coal. NOx emissions from each stack have been calculated from tender specifications, supplier guarantees, State Environment Protection Policy (SEPP) Schedule E limits and predicted emission levels from process modelling. Whilst natural gas contains ppm levels of sulfur, the assumption has been made that no SO_2 is formed from combustion of natural gas for the purpose of the modelling assessment. Also presented in Appendix B are modelled stack parameters for the DGDP.

3.2 Other Latrobe Valley sources

Maximum per stack NOx and SO_2 emissions from additional sources in the Latrobe Valley are derived from extensive historical stack testing data as reported by Black (1985) and utilised within Delaney (2007a). Emission rates and modelled stack parameters for these sources are also presented in Appendix B. Emissions from two seldom used gas turbine stations (Jeeralang A & B) have also been included with emissions information derived from EPA Vic. Discharge Licence LA93 for NOx and SO_2.

3.3 Nitrogen dioxide

Nitrogen oxides are emitted mainly in the form of nitric oxide (NO), but once released into the atmosphere are oxidised to nitrogen dioxide (NO_2). The predominant short-term transformation process is the reaction of nitric oxide with ambient ozone to form nitrogen dioxide: $NO + O_3 \rightarrow NO_2 + O_2$. Since the reaction is a 1 to 1 transformation that does not affect total NOx concentrations, the maximum extent of conversion of NO to NO_2 that can be expected in the emission plume is directly related to the maximum ambient concentration of ozone. One of the most common atmospheric chemistry issues a modelling assessment is required to address is estimating NO_2 from modelled NOx concentrations. Depending on the source, the amount of NO_2 in the exhaust stream as it is released is approximately 5 to 10% of total NOx.

To compensate for the transformation of NO to NO_2 for this particular assessment that occurs after the exhaust gases are discharged, oxidation to NO_2 when modelling the proposed 600MW power plant in conjunction with other Latrobe Valley sources has been estimated to be 30%, based on historical Latrobe Valley Air Monitoring Network (LVAMN) measurements (Delaney, 2007b) and Janssen *et al.* (1988). The NO_2/NOx ratio can be higher in townships where vehicles and domestic heating contribute to elevated levels of NOx and lower close to the emission sources. Where measured oxidation rates information exists for individual air quality stations, this has been used to predict ground level concentrations of NO_2 at the relevant site. Available oxidation rates relevant to each station are presented in Appendix C.

3.4 Particulate Matter

The highest concentrations of 24-hour particulate matter with an equivalent aerodynamic diameter of 10 micrometres or less (PM_{10}) measured in the Latrobe Valley can be attributed to bushfires and fuel reduction burning in summer and autumn, and which can have regional impacts far removed from the fire. Any elevated PM_{10} concentrations recorded in Latrobe Valley in recent years have indeed been attributed to bushfires, planned burning and local dust emissions (SKM, 2009). Agricultural, domestic, construction and open-cut mining activities also contribute to PM_{10} levels, with emissions from power station stacks having a small impact at ground level due to their height (Delaney, 2007a). Disregarding the effects of bushfire/planned burning activities, measurements in Latrobe Valley have shown that the State Environment Protection Policy (SEPP) Air Quality Objective for PM_{10} (50µg m^{-3}) is easily met (Black and Delaney, 2004). The proposed syngas-fuelled DGDP power station insures contributions of particulate matter will be insignificant from this site. Emission rates of PM_{10} from the proposed DGDP are expected to be 2 g s^{-1} from the Char Burners and 6 g s^{-1} from the CCGT units. In an associated assessment, DGDP PM_{10} emissions were modelled in conjunction with other Latrobe Valley PM_{10} sources and found to have negligible impact, with cumulative 99.9th percentile modelled concentrations not exceeding 20% of the PM_{10} Design Criteria.

4. METEOROLOGICAL DATA

The most suitable year for air quality modelling in terms of meteorological measurements in the Latrobe Valley is 1991. Meteorological stations where data were available extend to the extremities of the valley and include an acoustic sounder at Thoms Bridge providing data up to 1000m and a 110m meteorological tower at Flynn. The annual meteorological data used with CALPUFF was generated in two stages. The first stage utilises The Air Pollution Model (TAPM), a self-contained PC-based model developed by the Commonwealth Scientific and Industrial Organisation (CSIRO) Australia, and synoptic data and meteorological measurements in the Latrobe Valley to generate a 3-D meteorological dataset which includes winds, temperature profiles and mixing layer heights. Meteorological simulations have been carried out with one mother grid of 15km horizontal resolution and nested grids with horizontal resolutions of 4km and 1km. The second stage used output from TAPM (6 upper air stations, 2 surface stations) and surface measurements (6 stations) with diagnostic model CALMET V6.212 to generate the 3-D meteorological dataset for use with CALPUFF. TAPM configuration: GEODATA 9-second (~250m) terrain height database; default databases for land use, synoptic analyses and sea surface temperatures; 51 x 31 horizontal grid points; 25 vertical levels; outer grid of 15km and nesting grids of 4km and 1km; meteorological measurements at Latrobe Valley air quality and meteorological stations (see Figure 2).

In order to verify the integrity of the 1991 meteorological data set as being representative of present-day meteorological conditions in the Latrobe Valley, comparisons have been made with observed Latrobe Valley Air Monitoring Network wind speed and direction data from three meteorological stations - Moe, Rosedale South and Traralgon. The frequency distributions of occurrences of winds for each direction sector and for each wind class (wind rose) compare favourably with modelled data and are presented in Appendix C. The influence of local effects at the urban sites of Moe and Traralgon are evident, whereas the more rural site of Rosedale South displays no such effects. To further reinforce the validity of the 1991 meteorological data set, the prognostic model TAPM v4 has been used to produce meteorological data for the years 1991 and 2008 for LVAMN stations at Moe, Traralgon, Rosedale South and Jeeralang Hill for comparison with observed data (wind speed and direction, stability and mixing depth) at the same sites (where available). Results are contained within Appendix C. Also included in Appendix C are resultant concentrations of SO_2 emissions from Latrobe Valley sources (not including the proposed DGDP) that have been modelled using CALPUFF V 6.262, the 1991 meteorological data set and National Pollutant Inventory (NPI) emissions for the period 1 July 2007 to 30 June 2008. Results are shown via an assessment of the quality of the fit of the modelled (CALPUFF) percentile distribution of concentrations to the observed (LVAMN) percentile distribution of concentrations for SO_2 at Moe and Traralgon. Also shown in Appendix C are probability distributions of CALPUFF model predictions for SO_2 and NO_2 sourced from Delaney (2007b) using the 1991 CALMET meteorological file and emissions from existing power stations for LVAMN sites at Moe, Traralgon, Rosedale South and Jeeralang Hill. These compare well to probability distributions of measured LVAMN 1-hour SO_2 and NO_2 ground level concentrations.

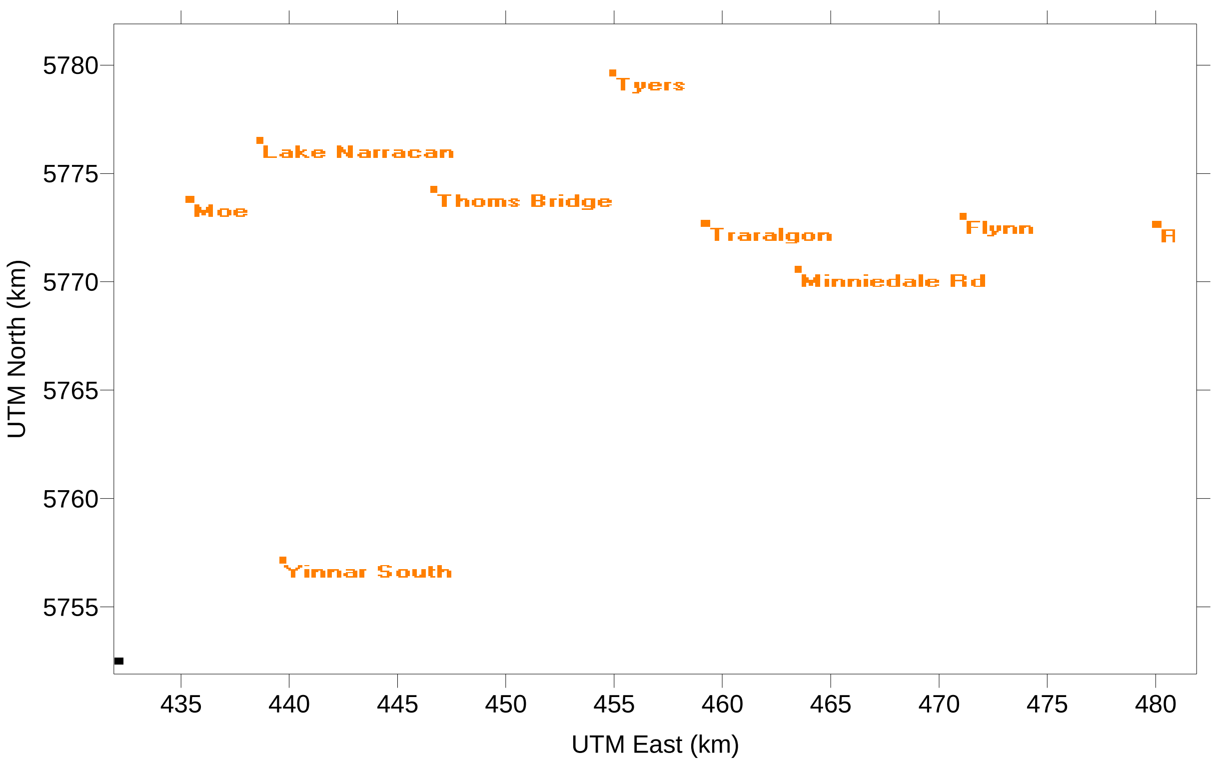

Figure 2. Latrobe Valley meteorological stations as used in TAPM.

5. ASSESSMENT CRITERIA

The Ambient Air Quality National Environment Protection Measure (NEPM) sets National goals for ambient air quality (NEPC, 2003). The Victorian State Environment Protection Policy (SEPP) (Ambient Air Quality) sets air quality objectives and goals for the State of

Victoria. The SEPP adopts the requirements of the NEPM (Ambient Air Quality) for six common pollutants. The SEPP (AAQ) standards apply to regional air quality and sites that are generally representative of general population exposure. The state of the atmosphere in the Latrobe Valley is determined by EPA Victoria on an annual basis by comparisons of the SEPP (AAQ) standards and goals with measurements undertaken at Moe and Traralgon, which forms part of the LVAMN.

5.1 Victorian Ambient Air Quality Assessment Criteria

In Victoria, the SEPP (AQM) provides Design Criteria for air pollutant Ground Level Concentrations (GLCs) for stacks and other air pollution source types. Design Criteria are indicators for assessing the potential impact of new or modified sources of emissions to air in Victoria and are formulated to protect the beneficial uses of the ambient air environment which includes the health and well being of human life.

The SEPP (AQM) defines air quality indicators as Class 1, 2, 3 or unclassified indicators depending on their likely distribution, toxicity, odour characteristic or hazard rating. This reflects the current understanding of the health effects of the pollutants, thereby ensuring that beneficial uses of the environment are protected, including life, health and well-being of humans, local amenity and aesthetic enjoyment and visibility.

Schedule A of the SEPP (AQM) provides Design Criteria for key pollutants for the purpose of assessment of proposals for new emission sources or modifications to existing emission sources. The Design Criteria expected to be of particular relevance for the assessment of air quality effects from the DGDP are set out in Table 1.

Table 1. SEPP (AQM) Schedule A – Design Criteria.

Pollutant	Averaging Period	Design Criteria
Nitrogen dioxide	1-hour	0.10 ppm
Sulfur dioxide	1-hour	0.17 ppm

5.2 Meteorological file

Meteorological data are one of the most important inputs into any air dispersion model. Ground-level concentrations of contaminants are primarily controlled by two meteorological elements: wind direction and speed (for transport), and turbulence and mixing height of the lower boundary layer (for dispersion).

The US EPA (2000) has developed protocols for the use of meteorological data files which provides guidance for the collection and processing of meteorological data for general use in air quality modelling applications. Section 5.3.2 of the guidance document reads:

> Regulatory analyses for the short-term ambient air quality standards (1 to 24-hour averaging) involve the sequential application of a dispersion model to every hour in the analysis period (one to five years); such analyses require a meteorological record for every hour in the analysis period. Substitution for missing or invalid data is used to meet this requirement. Applicants in regulatory modelling analyses are allowed to substitute for up to 10 percent of the data; conversely, the meteorological data base must be 90 percent complete (before substitution) in order to be acceptable for use in regulatory dispersion modelling.

The 1991 meteorological data file utilised in this assessment satisfies the above guideline.

6. RESULTS

Predicted 1-hour cumulative ground level concentrations of NO_2 and SO_2 resulting from the proposed 600MW Dual Gas Demonstration Project in conjunction with other emission sources, utilising the advanced non-steady-state air quality modelling system CALPUFF, are presented in Table 2 and compared with the associated Design Criteria. A reliable and accepted approach is to use the 99.9th percentile values for one-hour concentrations as the maximum ground-level concentrations likely to occur. This is the highest ground-level concentration at each receptor after the highest 0.1% of predictions has been discarded. Ground-level concentration contour plots resulting from the modelling are presented in Appendix D.

Table 2. Dispersion modelling results for NO_2 and SO_2 from the proposed 600MW Dual Gas Demonstration Project plus other Latrobe Valley sources at a spatial resolution of 1-km utilising full syngas production with supplementary natural gas duct firing. 1-hour time average. 1-year simulation period. 30% conversion of NOx to NO_2.

Pollutant	Averaging Period	Design Criteria (ppm)	99.9th percentile modelled value (ppm)
Nitrogen dioxide	1-hour	0.10	0.05
Sulfur dioxide	1-hour	0.17	0.15

Predicted 1-hour ground level concentrations of NO_2 resulting from 100% natural gas operation of the proposed 600MW Dual Gas Demonstration Project has also been assessed. Modelling results are listed below in Table 3.

Table 3. Dispersion modelling results for NO_2 from the proposed 600MW Dual Gas Demonstration Project plus other Latrobe Valley sources at a spatial resolution of 1-km utilising 100% natural gas operation. 1-hour time average. 1-year simulation period. 30% conversion of NOx to NO_2.

Pollutant	Averaging Period	Design Criteria (ppm)	99.9th percentile modelled value (ppm)
Nitrogen dioxide	1-hour	0.10	0.05

A total of 21 discrete receptors were included in the modelling assessment. Modelled 1-hour 99.9th percentile concentration values at all sites and including present-day Latrobe Valley Air Monitoring Network (LVAMN) stations located at Moe, Traralgon, Rosedale South and Jeeralang Hill are listed below in Tables 4 - 6, as are results for the four homesteads to the southeast of the proposed power plant that have also been identified as sensitive receptors (SKM, 2009).

Table 4. Discrete receptor modelling results for NO_2 from the proposed 600MW Dual Gas Demonstration Project plus other Latrobe Valley sources at a spatial resolution of 1-km utilising full syngas production with supplementary natural gas duct firing. 1-hour time average. 1-year simulation period.

Receptor	UTM coordinates (km)		99.9th percentile modelled value (ppm)
1 - Driffield	437.3	5763	0.0203
2 - Hazelwood Estate	446.3	5758.4	0.0223
3 - Clarkes Road	456.9	5762.3	0.0216
4 - Glengarry	459.8	5778.7	0.0093
5 - Morwell West	446.1	5768.1	0.0230
6 - Thoms Bridge	446.4	5773.9	0.0146
7 - Minniedale Road	463.6	5770.1	0.0174
8 - Moe	434.9	5773.4	0.0146
9 - Traralgon	459.2	5772.3	0.0276
10 - Morwell East	449.6	5768.3	0.0275
11 - Rosedale South	480.5	5772.2	0.0116
12 - Yinnar South	439.3	5756.3	0.0220
13 - Tyers	454.8	5779.4	0.0243
14 - Lake Narracan	438.2	5776.2	0.0095
15 - Gormandale	472.8	5764.5	0.0228
16 - Flynns Creek	464.8	5767.4	0.0175
17 - Jeeralang Hill	454	5755.5	0.0416
18 - Homestead 1	451.269	5765.943	0.0242
19 - Homestead 2	449.936	5764.332	0.0244
20 - Homestead 3	450.312	5763.860	0.0226
21 - Homestead 4	450.806	5764.298	0.0219

Table 5. Discrete receptor modelling results for SO_2 from the proposed 600MW Dual Gas Demonstration Project plus other Latrobe Valley sources at a spatial resolution of 1-km utilising full syngas production with supplementary natural gas duct firing. 1-hour time average. 1-year simulation period.

Receptor	UTM coordinates (km)		99.9th percentile modelled value (ppm)
1 - Driffield	437.3	5763	0.0633
2 - Hazelwood Estate	446.3	5758.4	0.0630
3 - Clarkes Road	456.9	5762.3	0.0939
4 - Glengarry	459.8	5778.7	0.0363
5 - Morwell West	446.1	5768.1	0.0642
6 - Thoms Bridge	446.4	5773.9	0.0440
7 - Minniedale Road	463.6	5770.1	0.0598
8 - Moe	434.9	5773.4	0.0260
9 - Traralgon	459.2	5772.3	0.0569
10 - Morwell East	449.6	5768.3	0.0768
11 - Rosedale South	480.5	5772.2	0.0566
12 - Yinnar South	439.3	5756.3	0.0596
13 - Tyers	454.8	5779.4	0.0714
14 - Lake Narracan	438.2	5776.2	0.0268
15 - Gormandale	472.8	5764.5	0.0706
16 - Flynns Creek	464.8	5767.4	0.0915
17 - Jeeralang Hill	454	5755.5	0.0952
18 - Homestead 1	451.269	5765.943	0.0694
19 - Homestead 2	449.936	5764.332	0.0708
20 - Homestead 3	450.312	5763.860	0.0709
21 - Homestead 4	450.806	5764.298	0.0679

Table 6. Discrete receptor modelling results for NO_2 from the proposed 600MW Dual Gas Demonstration Project plus other Latrobe Valley sources at a spatial resolution of 1-km utilising 100% natural gas operation. 1-hour time average. 1-year simulation period.

Receptor	UTM coordinates (km)		99.9th percentile modelled value (ppm)
1 - Driffield	437.3	5763	0.0200
2 - Hazelwood Estate	446.3	5758.4	0.0219
3 - Clarkes Road	456.9	5762.3	0.0211
4 - Glengarry	459.8	5778.7	0.0090
5 - Morwell West	446.1	5768.1	0.0223
6 - Thoms Bridge	446.4	5773.9	0.0140
7 - Minniedale Road	463.6	5770.1	0.0174
8 - Moe	434.9	5773.4	0.0144
9 - Traralgon	459.2	5772.3	0.0276
10 - Morwell East	449.6	5768.3	0.0261
11 - Rosedale South	480.5	5772.2	0.0114
12 - Yinnar South	439.3	5756.3	0.0216
13 - Tyers	454.8	5779.4	0.0228
14 - Lake Narracan	438.2	5776.2	0.0095
15 - Gormandale	472.8	5764.5	0.0224
16 - Flynns Creek	464.8	5767.4	0.0175
17 - Jeeralang Hill	454	5755.5	0.0415
18 - Homestead 1	451.269	5765.943	0.0240
19 - Homestead 2	449.936	5764.332	0.0243
20 - Homestead 3	450.312	5763.860	0.0226
21 - Homestead 4	450.806	5764.298	0.0219

7. DISCUSSION & CONCLUSION

An air quality modelling assessment to predict concentration levels of NO_2 and SO_2 from a proposed 600MW Dual Gas Demonstration Project, utilising the advanced non-steady-state air quality modelling system CALPUFF, has been carried out. Dispersion modelling has been completed in conjunction with other Latrobe Valley emission sources (Energy Brix, Hazelwood, Yallourn, Loy Yang A & B, Jeeralang A & B power stations, and Australian Paper). The inclusion of the seldom utilised Jeeralang A and B gas fired stations resulted in no increase in modelled concentrations for any pollutant when compared with modelled results that did not include these sources. PM_{10} emissions from the site of interest have been separately assessed in conjunction with other Latrobe Valley sources and found to have negligible impact.

An annual meteorological file has been developed for use with CALPUFF using the TAPM/CALMET meteorological models and Latrobe Valley Air Monitoring Network meteorological data. The long-term LVAMN database is a unique and immensely valuable resource for air quality research and environmental management in eastern Victoria. The 1991 meteorological data file, in particular, provides a unique dataset of a full year of data for a period when air quality monitoring stations were located over the length and breadth of the Latrobe Valley. A review of the 1991 Latrobe Valley meteorological data file shows it complies with US EPA protocols for the collection and processing of meteorological data for general use in air quality modelling applications, and comparison of dispersion modelling results using the 1991 meteorological data file with measured data from more recent years indicates good agreement. On a monthly basis, seasonal trends as generated by TAPM v4 are as expected with the highest mixing depth predictions occurring during the summer months and reasonable agreement occurring between the two modelled years of 1991 and 2008, particularly in January. However, mixing depth values in winter months are higher for 1991 which may result in increased dispersion and lower ground level concentrations being modelled. Nonetheless, this result may also be within what would be expected for reasonable year to year variation. The percentage of measured unstable (A+B+C) atmospheric stability categories shows that TAPM v4 1991, CALMET 1991 and measured (LVAMN) results are similar for 1991 at Moe and Traralgon, with TAPM v4 2008 being less aligned with measured results, but the opposite occurring at the rural site of Rosedale South. Also at Rosedale South, measured results for 1991 and 2008 for all stability categories are very similar (LVAMN stability results for 2008 at Moe and Traralgon were not available), meaning not much has changed in the 1991 to 2008 period at this site, which is unhindered by the influence of local effects present in more urban areas. For all stability categories across the three sites of interest, there is very good agreement between CALMET 1991 and measured LVAMN data. The 1991 meteorological file for the Latrobe Valley produced for use with dispersion modelling is acknowledged as being superior to any file that could be developed today.

Concerning the proposed DGPL site location, sea breezes are a prominent feature of the Latrobe Valley, particularly in the warmer months, as is the convergence of sea breezes from different coastlines. The role of sea breezes in the dispersion of pollutants in the Latrobe Valley is therefore an important consideration. Plumes from Latrobe Valley sources generally drift towards the coastline before meeting the incoming sea breeze. One could therefore speculate that the possibility exists for the sea breeze to transport emissions back up the valley, whence they came. Physick and Abbs (1991) carried out extensive analysis into this possibility and the role of sea breezes in the dispersion of pollutants.

Concentrating on summertime conditions where weak synoptic winds and clear skies dominate, Physick and Abbs found that the wind field is indeed dominated by sea breezes from the east and south coasts of the region. The inland penetration of the east coast sea breeze was such that by early evening easterly winds are found throughout the valley below a height of approximately 1500m. Westerly winds existed between the 1500 and 3000m levels, which descended during the night such that by late next morning, the valley winds at all levels between the surface and 3000m were from the west.

Using this time-dependant behaviour of the wind field and the vertical wind and temperature structure of the sea breeze, Physick and Abbs examined the dispersion of pollutant plumes from power generators (Yallourn, Hazelwood, Loy Yang and Morwell - now Energy Brix Australia Corporation) in the central part of the valley. Due primarily to the siting of these sources (approximately 90km inland from the coast), they discovered that the easterly sea breeze replaces polluted air with clean air as it moves up the valley. Air in the polluted mixed layer rose at the front and was mixed into the return flow of the sea breeze. During the night, emissions are transported above ground level out of the western end of the valley, while plume material released earlier in the day continues to cross the east coast in the upper-level westerly winds.

In summary, Physicks and Abbs findings suggest that the sea breezes replace polluted mixed-layer air with clean air as they penetrate up the valley, and that plume contents are advected (i.e. flushed) out of each end of the valley at upper levels overnight. Whether the result of good fortune or good design, these findings suggest the Latrobe Valley power generators, including the proposed DGPL site, are located such that favourable opportunity exists for the successful transport of pollutants away from the population zones of the Latrobe Valley.

Additionally, in both isolation and in conjunction with other Latrobe Valley sources, modelled 99.9th percentile ground level concentrations for NO_2 and SO_2 as predicted by CALPUFF are below concentrations permitted by the the State Environment Protection Policy (SEPP) Design Ground Level Concentrations (DGLCs) of 0.10ppm and 0.17ppm respectively.

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APPENDIX A

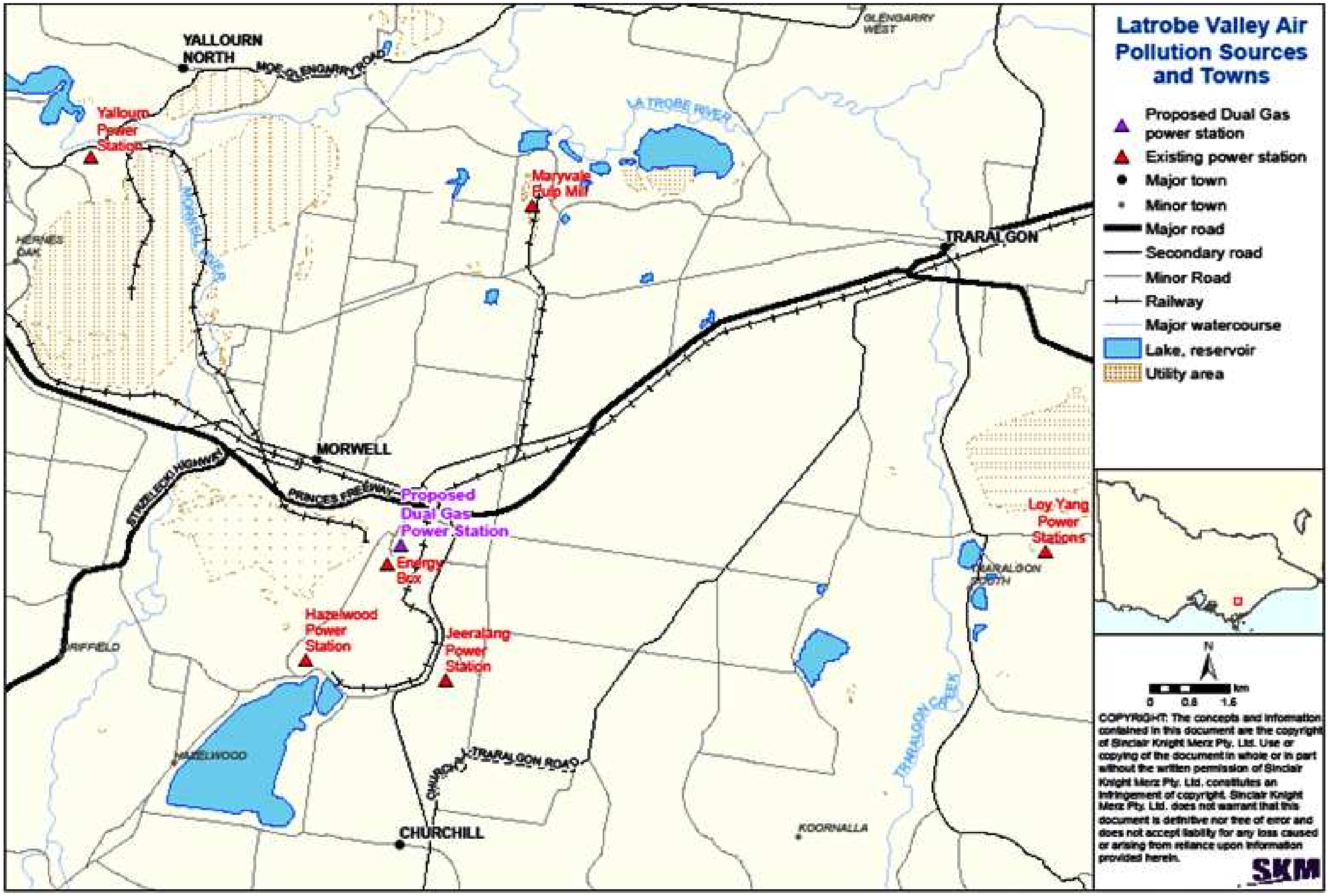


Figure A1. Proposed Dual Gas Demonstration Project Power Station site location. Source: SKM (2009).

APPENDIX B Modelled emissions and stack parameters

Table B1. Modelled emission rates – proposed Dual Gas Demonstration Project Power Station.

	CCGT 1	CCGT 2	Char Burner 1	Char Burner 2	Air Pre Heater 1	Air Pre Heater 2	Pre Dryer 1	Pre Dryer 2
NOx ($g\ s^{-1}$) - syngas with supplementary NG firing	32.57	32.57	12.82	12.82	0.19	0.19	1.21	1.21
SO_2 ($g\ s^{-1}$) - syngas with supplementary NG firing	195.01	195.01	9.22	9.22	-	-	-	-
NOx ($g\ s^{-1}$) - 100% NG operation	28.51	28.51	1.40	1.40	-	-	-	-
SO_2 ($g\ s^{-1}$) - 100% NG operation	-	-	-	-	-	-	-	-

CCGT = Combined Cycle Gas Turbine.; NG = Natural Gas

Table B2. Modelled emission rates – other sources.

	Loy Yang A and B	Yallourn Units 1 and 2	Yallourn Units 3 and 4	Hazel -wood	Energy Brix	AP Source 1	AP Source 2	AP Source 3	AP Source 4	AP Source 5	AP Source 6	AP Source 7	Jeera -lang A & B
NOx ($g\ s^{-1}$)	581	287	271	150	38	4.8	5	4.9	1.5	2.7	1.8	3.5	31.67
SO_2 ($g\ s^{-1}$)	1630	387	365	130	33	32.2	0	6.5	0.21	0	2	0	0.64

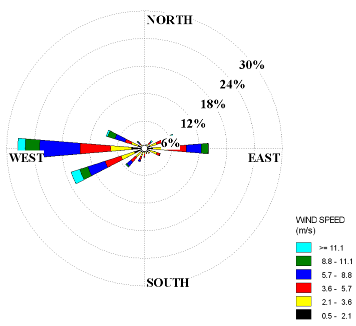
Table B3. Modelled stack parameters – proposed Dual Gas Demonstration Project Power Station.

	Easting (m)	Northing (m)	Stack elevation (m asl)	Stack height (m)	Stack diameter (m)	Stack temp (K)	Stack exit velocity (m s^{-1})
CCGT 1	448,605	5,766,045	87	80	5.05	417	33
CCGT 2	448,643	5,766,029	88	80	5.05	417	33
Char Burner 1	448,603	5,766,002	88	80	1.37	423	32.8
Char Burner 2	448,590	5,765,973	88	80	1.37	423	32.8
Air Pre Heater 1	448,559	5,766,088	88	80	0.43	623	33.1
Air Pre Heater 2	448,572	5,766,080	88	80	0.43	623	33.1
Pre Dryer 1	448,547	5,766,040	88	80	1.31	416	33.2
Pre Dryer 2	448,522	5,765,982	88	80	1.31	416	33.2
CCGT 1 - 100% NG	448,605	5,766,045	87	80	5.05	415	33.4
CCGT 2 - 100% NG	448,643	5,766,029	88	80	5.05	415	33.4
Char Burner 1 - 100% NG	448,603	5,766,002	88	80	1.37	407	16.6
Char Burner 2 - 100% NG	448,590	5,765,973	88	80	1.37	407	16.6

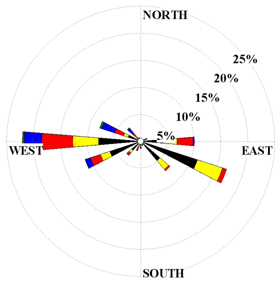
Table B4. Modelled stack parameters – other sources.

	Number of point sources	Stack elevation (m asl)	Stack height (m)	Stack diameter (m)	Stack temp (K)	Stack exit velocity (m s^{-1})
Loy Yang A	2	110	260	11	448	30.2
Loy Yang B	1	115	255	11	448	28.4
Yallourn Stage 1	1	61	168	10.7	468	23.9
Yallourn Stage 2	1	61	168	10.7	470	26.2
Hazelwood	8	85	137	6.4	488	22.8
Energy Brix	4	73	92	5.5	573	13.0
Australian Paper	7	39 - 51	50 - 75	0.6 - 2.6	361 - 463	10 - 29
Jeeralang A & B	7	89	32	4.7 - 5.2	706 - 789	35 - 39

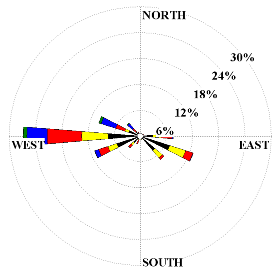
APPENDIX C Validation information for 1991 meteorological data.



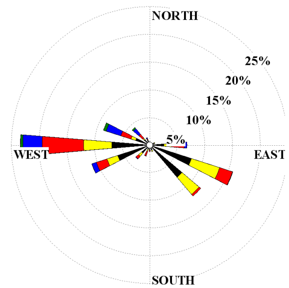
CALMET_MOE_1991



LVAMN_MOE_2001



LVAMN_MOE_2002



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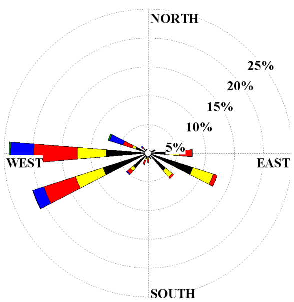

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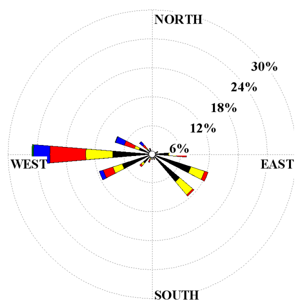

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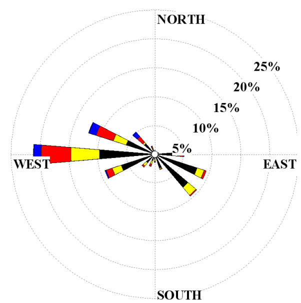
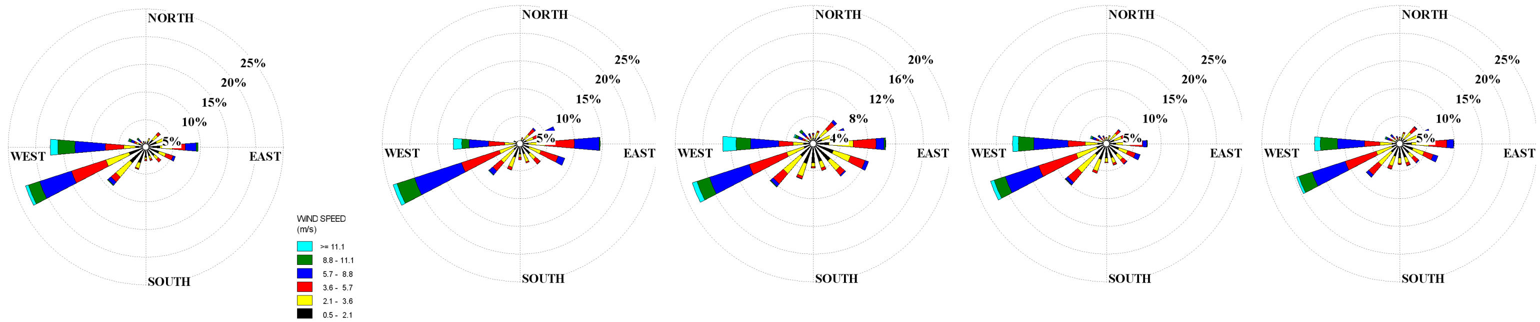
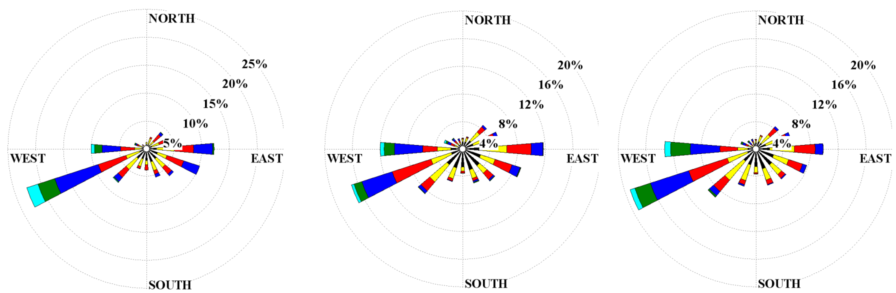


LVAMN_MOE_2006

**Figure C1. Modelled wind data (CALMET) and LVAMN measured wind speed and direction data - Moe.
Raw data source for LVAMN: EPA Victoria, Air Quality Studies - Centre for Environmental Sciences.**



CALMET_RS_1991 LVAMN_RS_2002 LVAMN_RS_2003 LVAMN_RS_2004 LVAMN_RS_2005



LVAMN_RS_2006 LVAMN_RS_2007 LVAMN_RS_2008

Figure C2. Modelled wind data (CALMET) and LVAMN measured wind speed and direction data - Rosedale South. Raw data source for LVAMN: EPA Victoria, Air Quality Studies - Centre for Environmental Sciences.

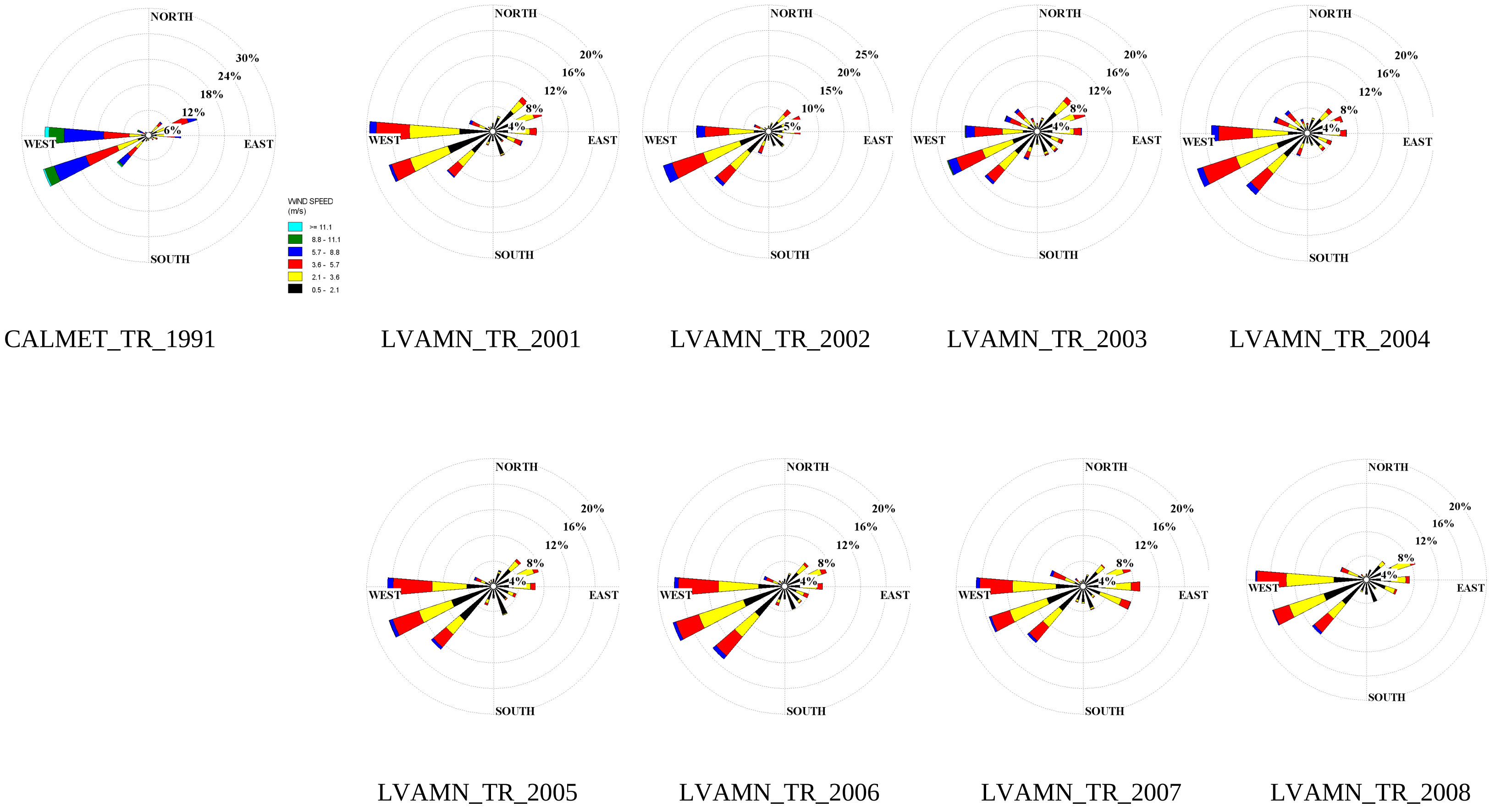


Figure C3. Modelled wind data (CALMET) and LVAMN measured wind speed and direction data - Traralgon. Raw data source for LVAMN: EPA Victoria, Air Quality Studies - Centre for Environmental Sciences.

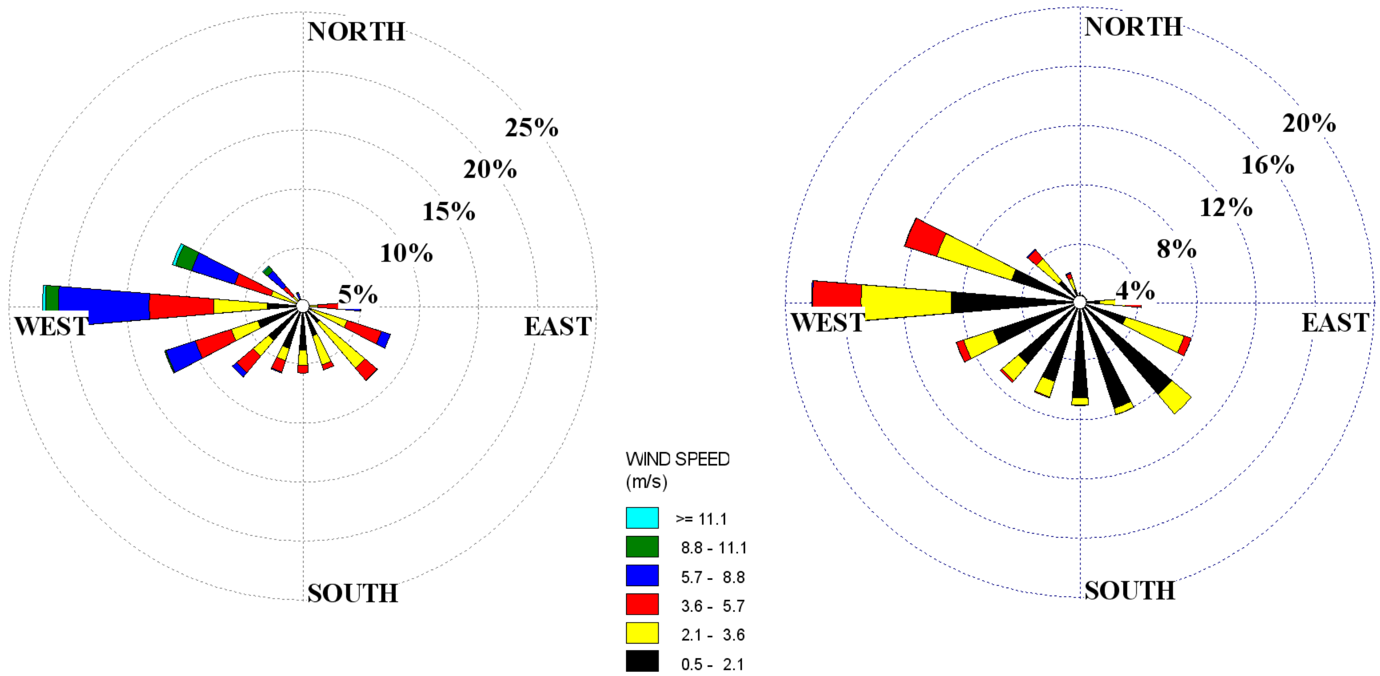


Figure C4. TAPM v4 wind data for 1991 (L) and 2008 (R) – Moe.

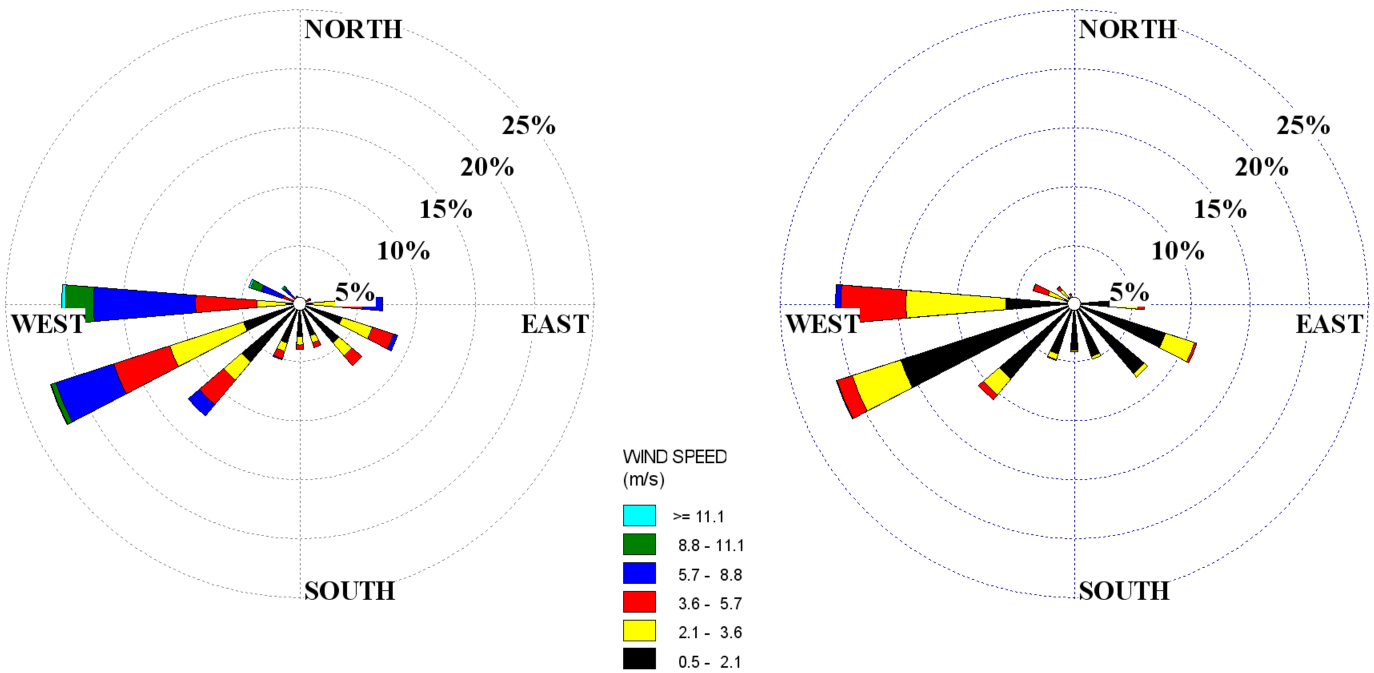


Figure C5. TAPM v4 wind data for 1991 (L) and 2008 (R) – Traralgon.

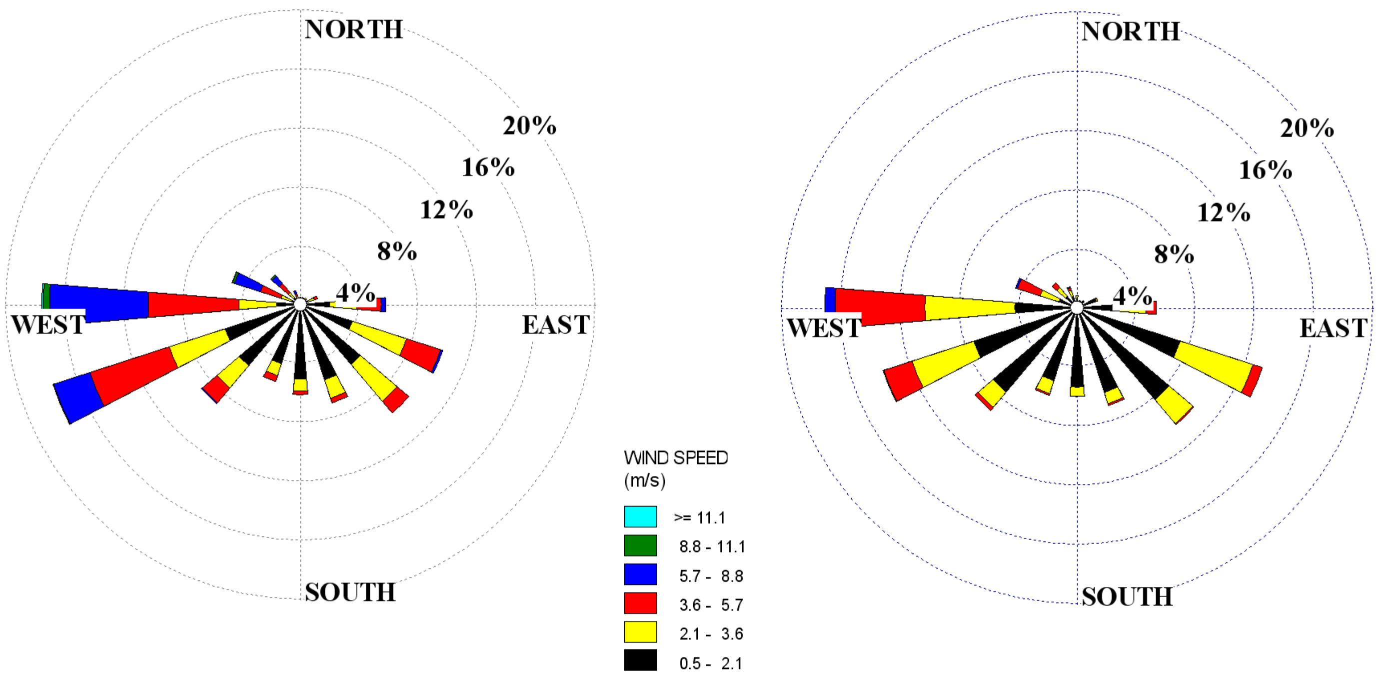


Figure C6. TAPM v4 wind data for 1991 (L) and 2008 (R) – Rosedale South.

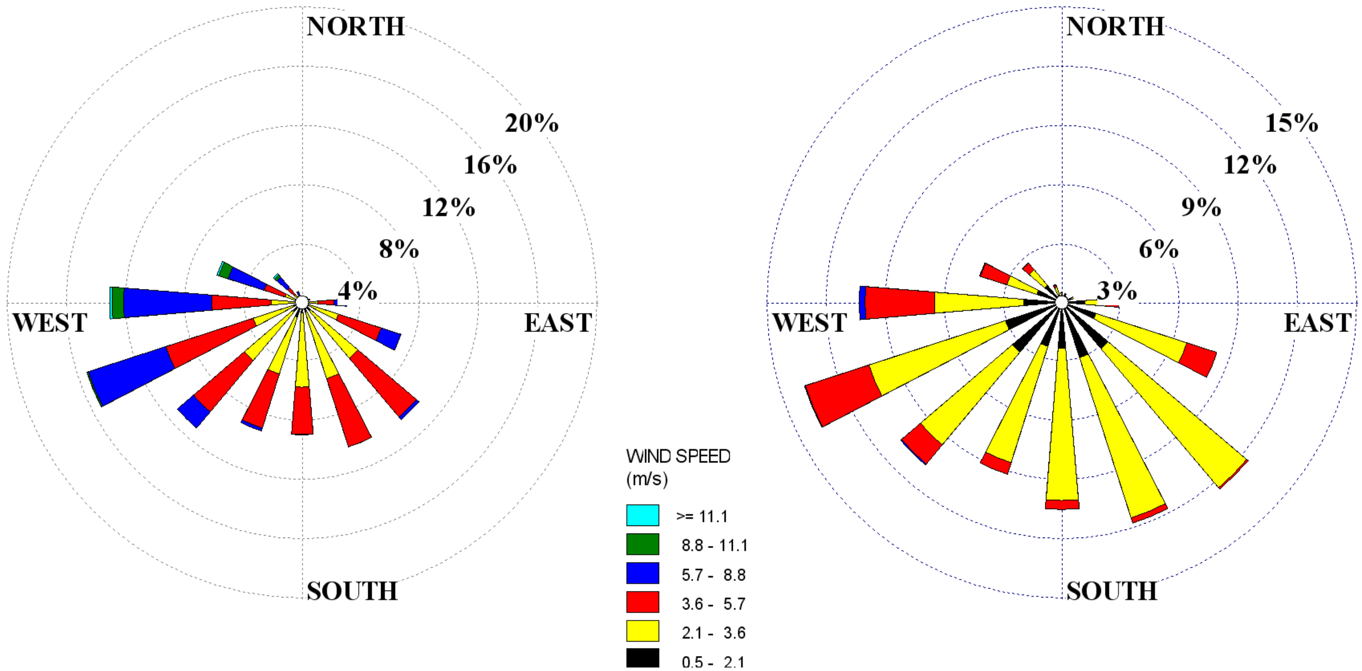


Figure C7. TAPM v4 wind data for 1991 (L) and 2008 (R) – Jeeralang Hill.

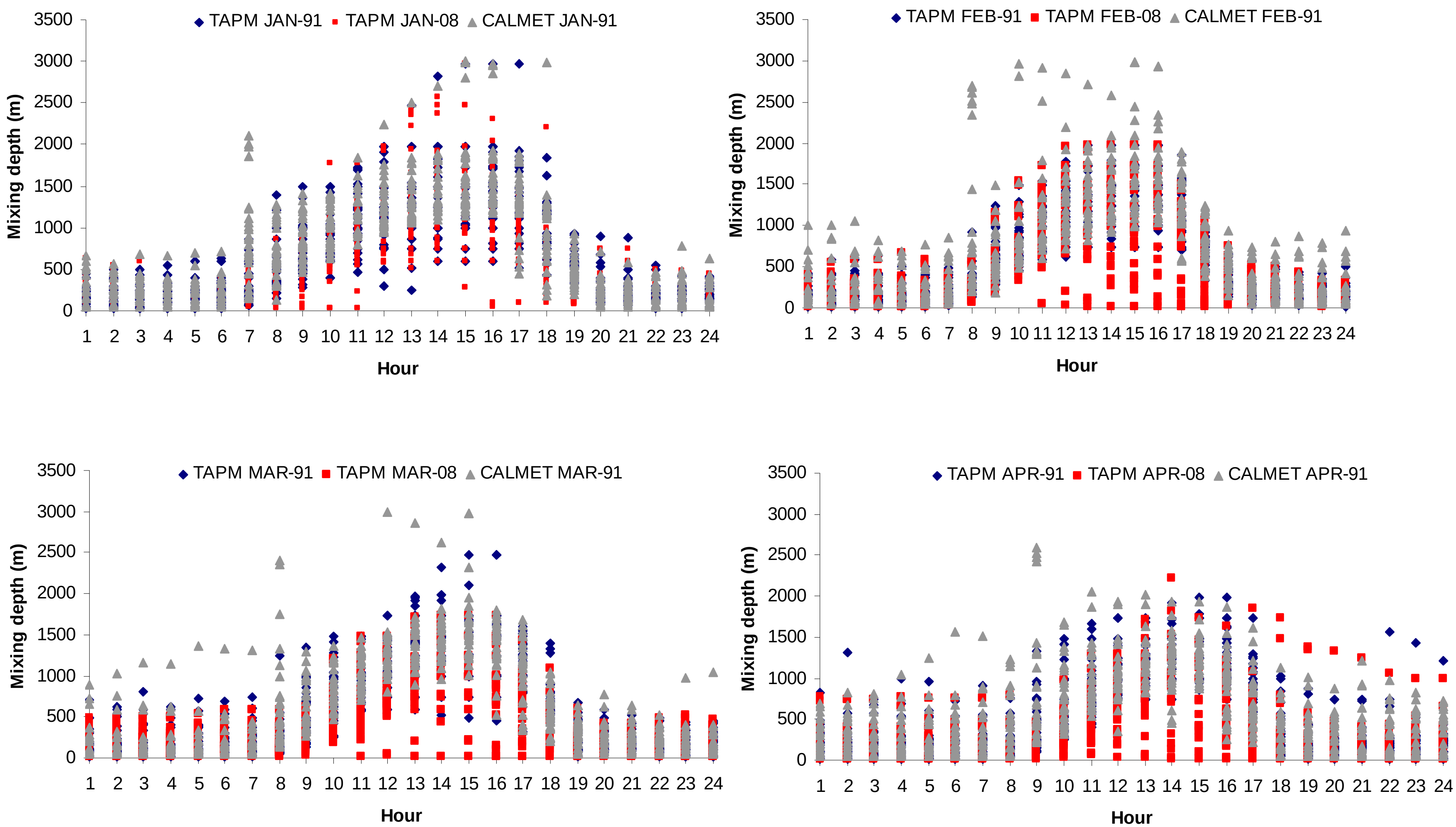


Figure C8. TAPM v4 and CALMET monthly mean mixing depth for January to April – 1991 and 2008 – Moe.

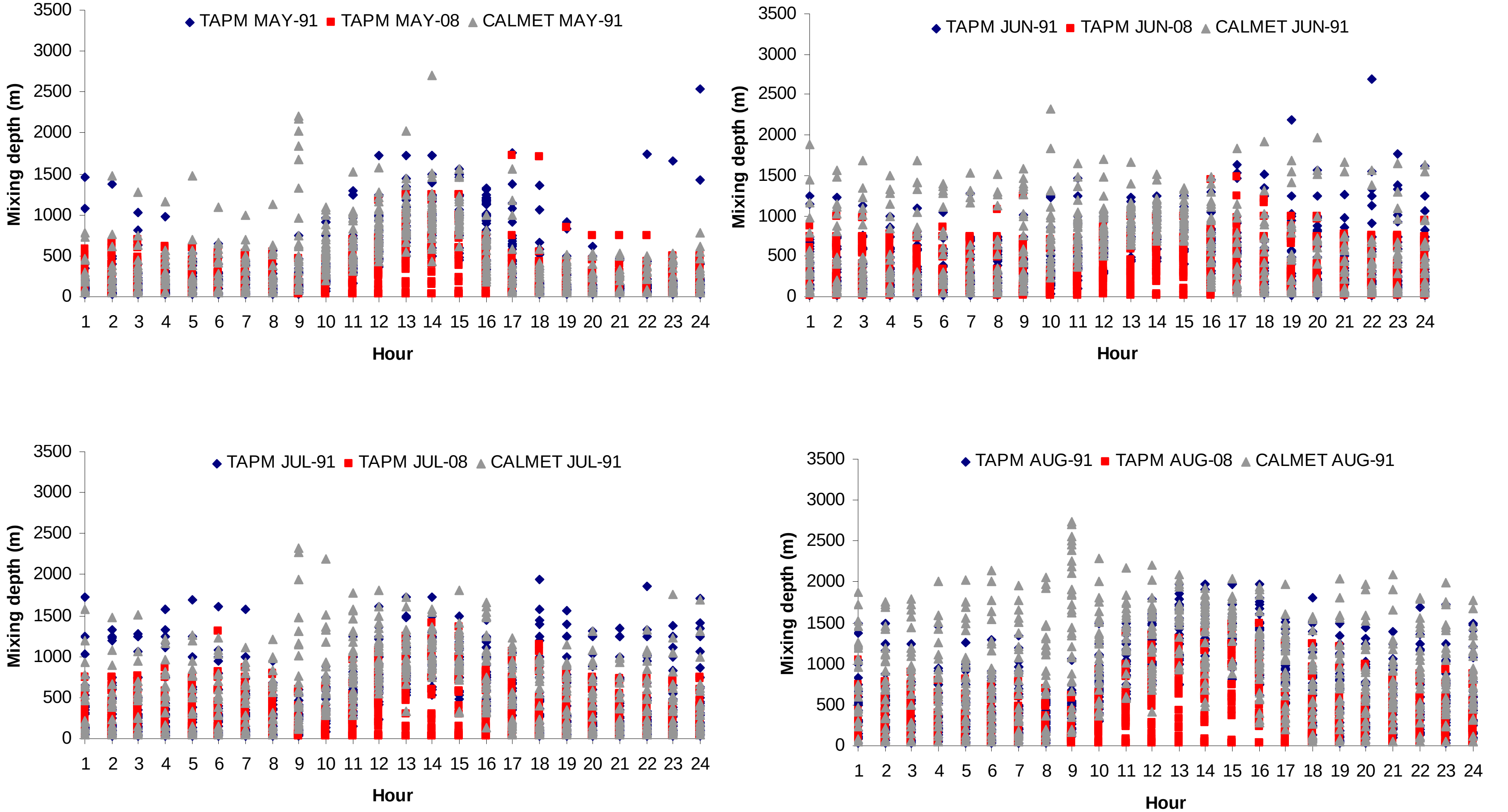
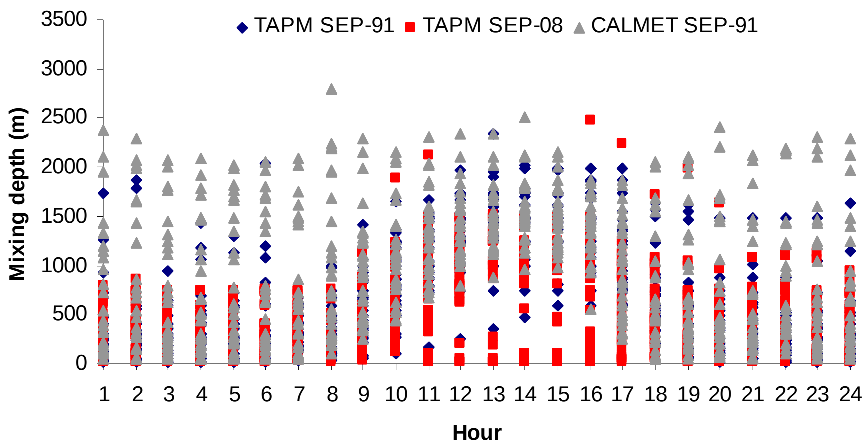
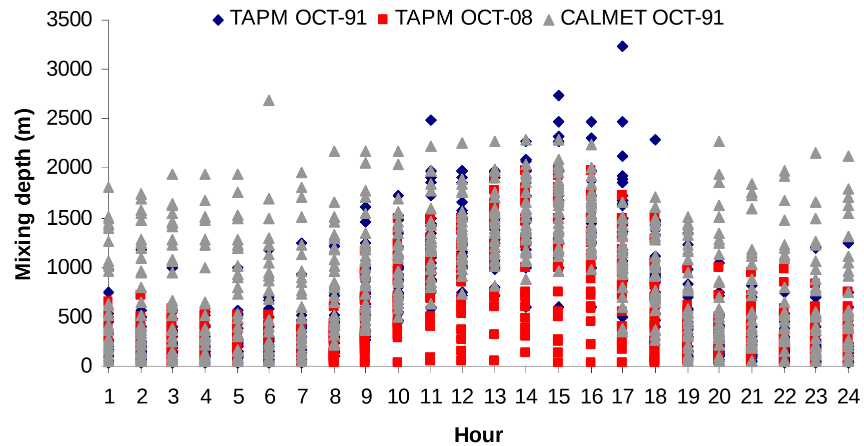
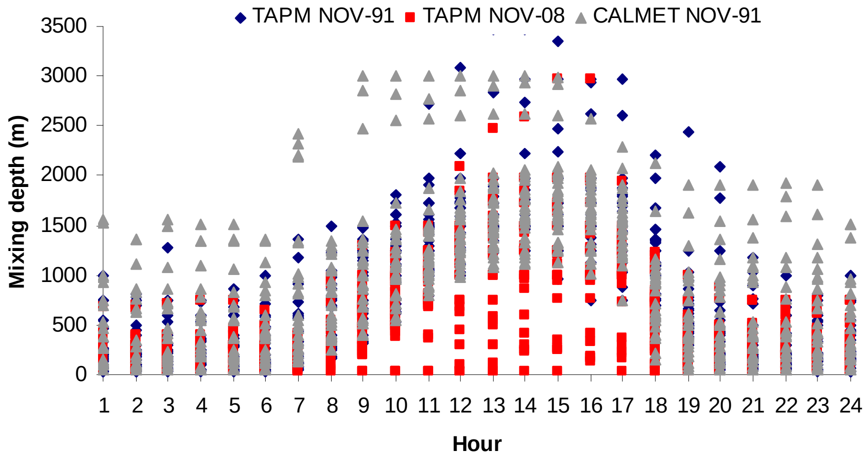


Figure C9. TAPM v4 and CALMET monthly mean mixing depth for May to August – 1991 and 2008 – Moe.







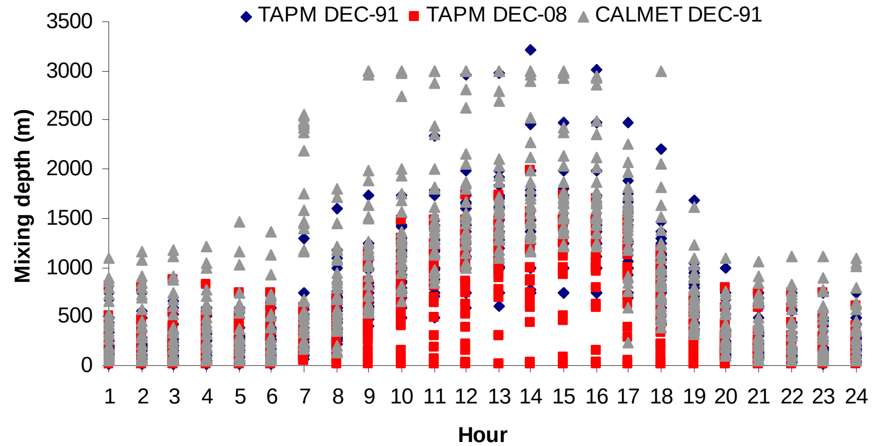


Figure C10. TAPM v4 and CALMET monthly mean mixing depth for September to December – 1991 and 2008 – Moe.

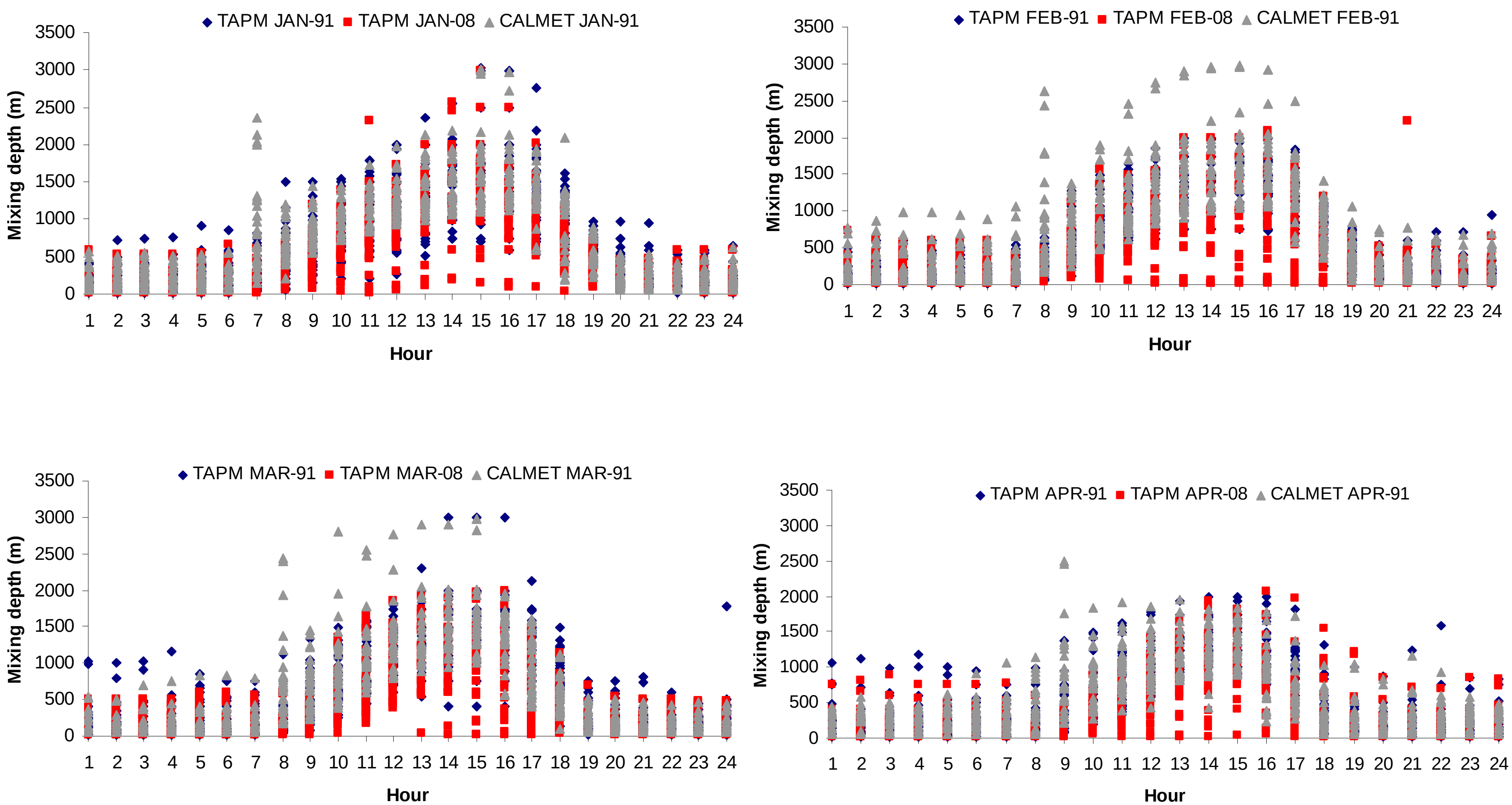


Figure C11. TAPM v4 and CALMET monthly mean mixing depth for January to April – 1991 and 2008 – Traralgon.

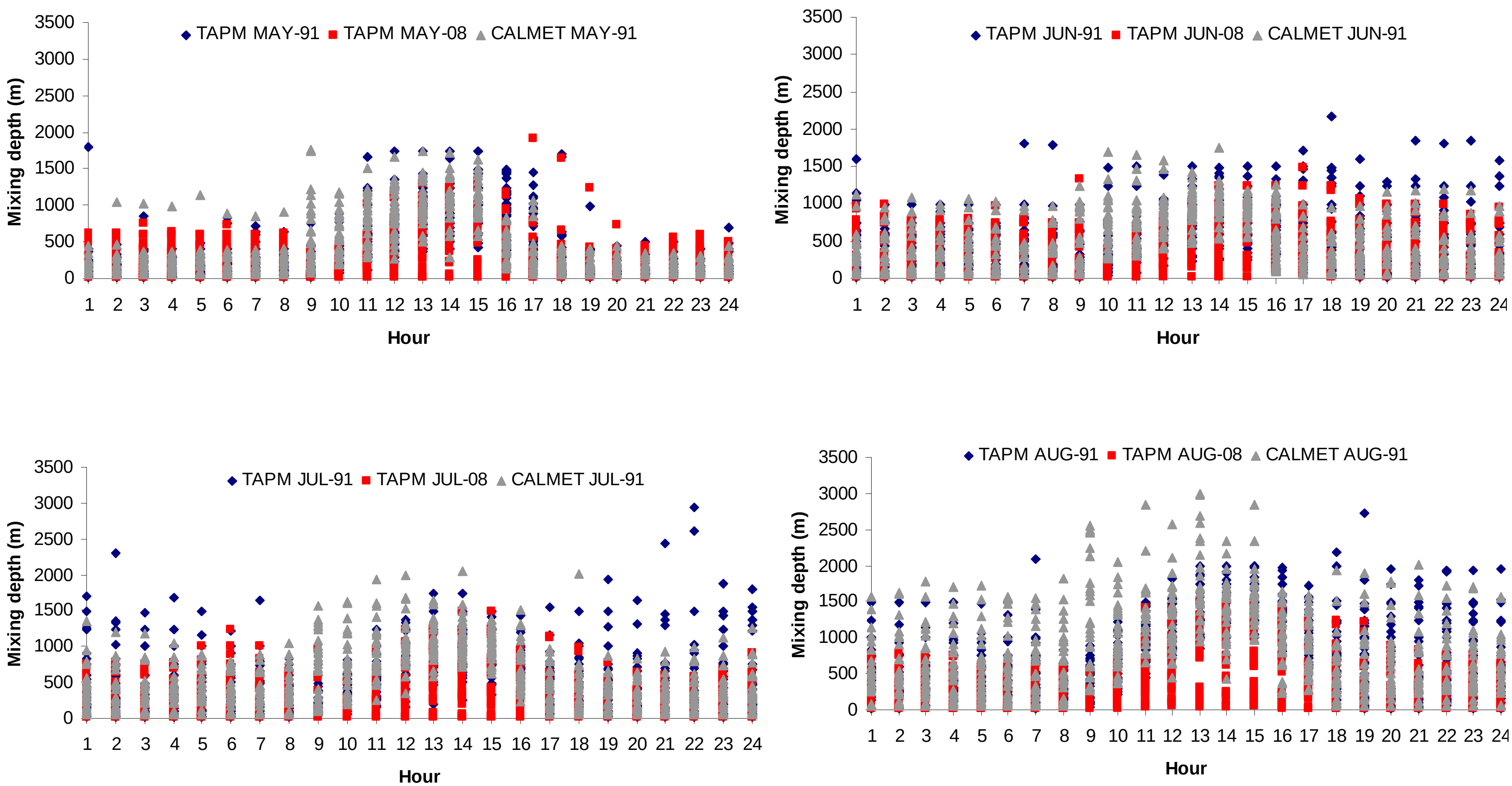


Figure C12. TAPM v4 and CALMET monthly mean mixing depth for May to August – 1991 and 2008 – Traralgon.

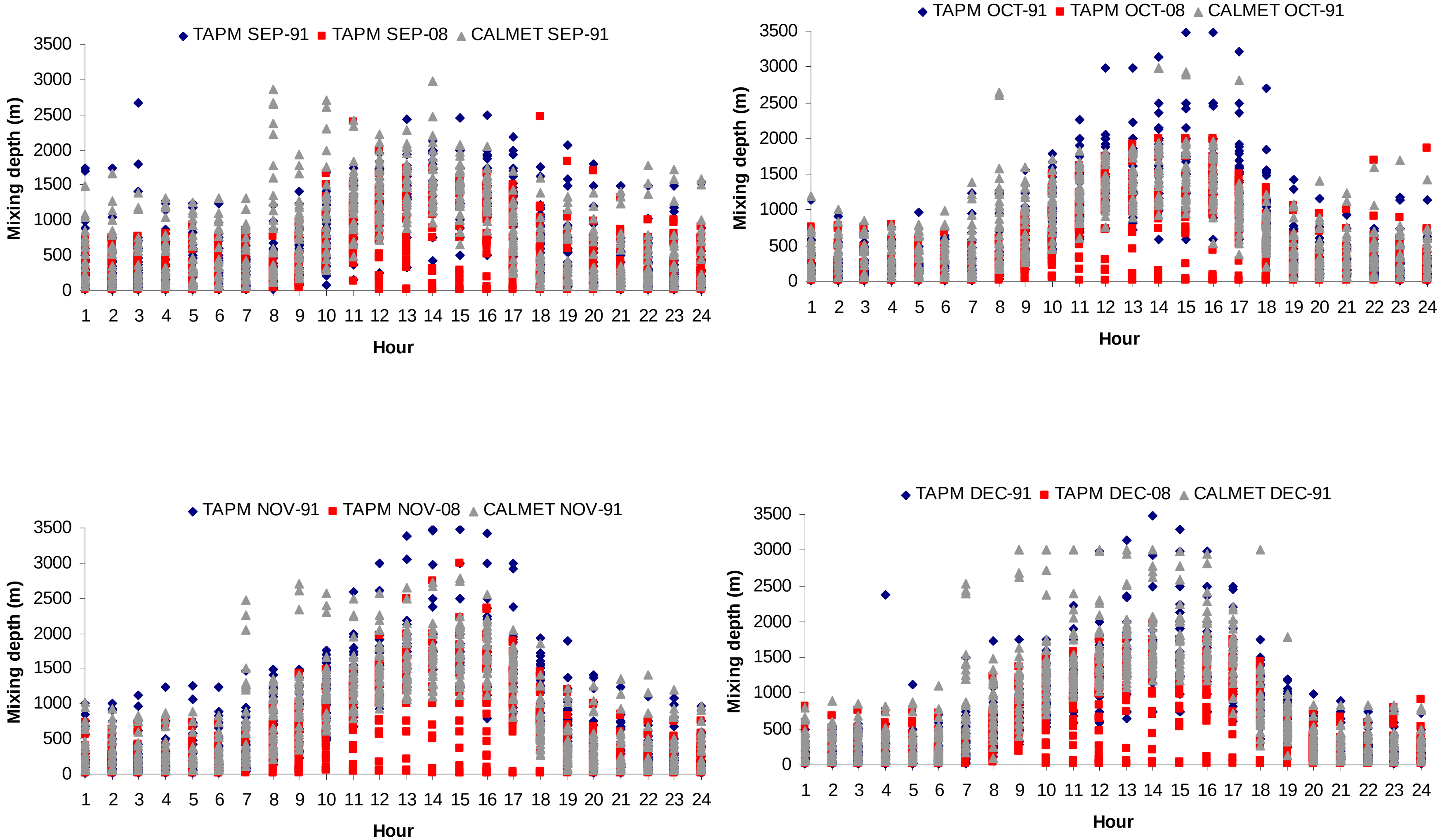


Figure C13. TAPM v4 and CALMET monthly mean mixing depth for September to December – 1991 and 2008 – Traralgon.

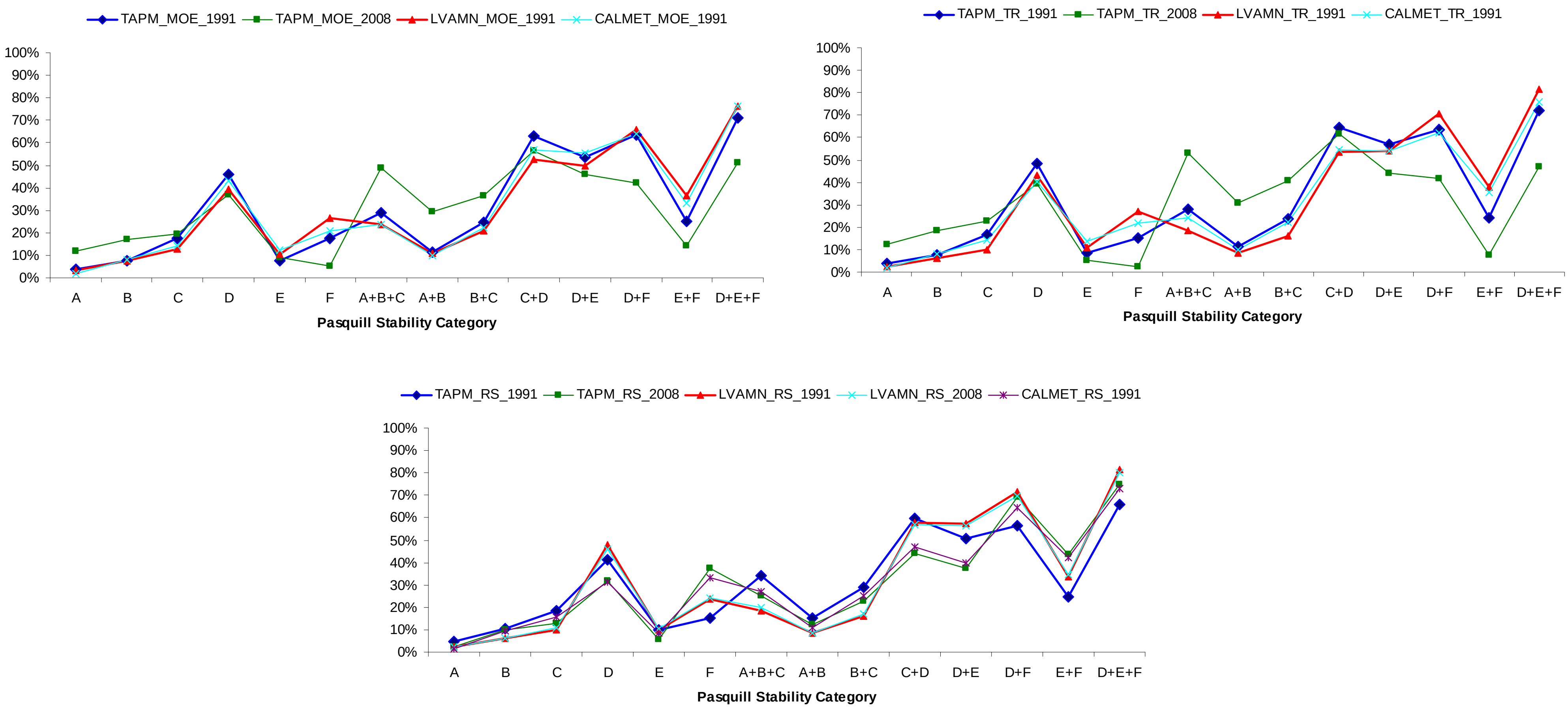


Figure C14. TAPM v4, CALMET and measured atmospheric stability classes – Moe (top left), Traralgon (top right) and Rosedale South (bottom) – 1991 and 2008. Raw data source for LVAMN: EPA Victoria, Air Quality Studies - Centre for Environmental Sciences.

Table C1. NO_2/NO_X ratios based on historical Latrobe Valley Air Monitoring Network (LVAMN) measurements.

LVAMN Air Quality Station	**NO_2/NO_X**
Moe	0.50
Traralgon	0.56
Rosedale South	0.30
Jeeralang Hill	0.45

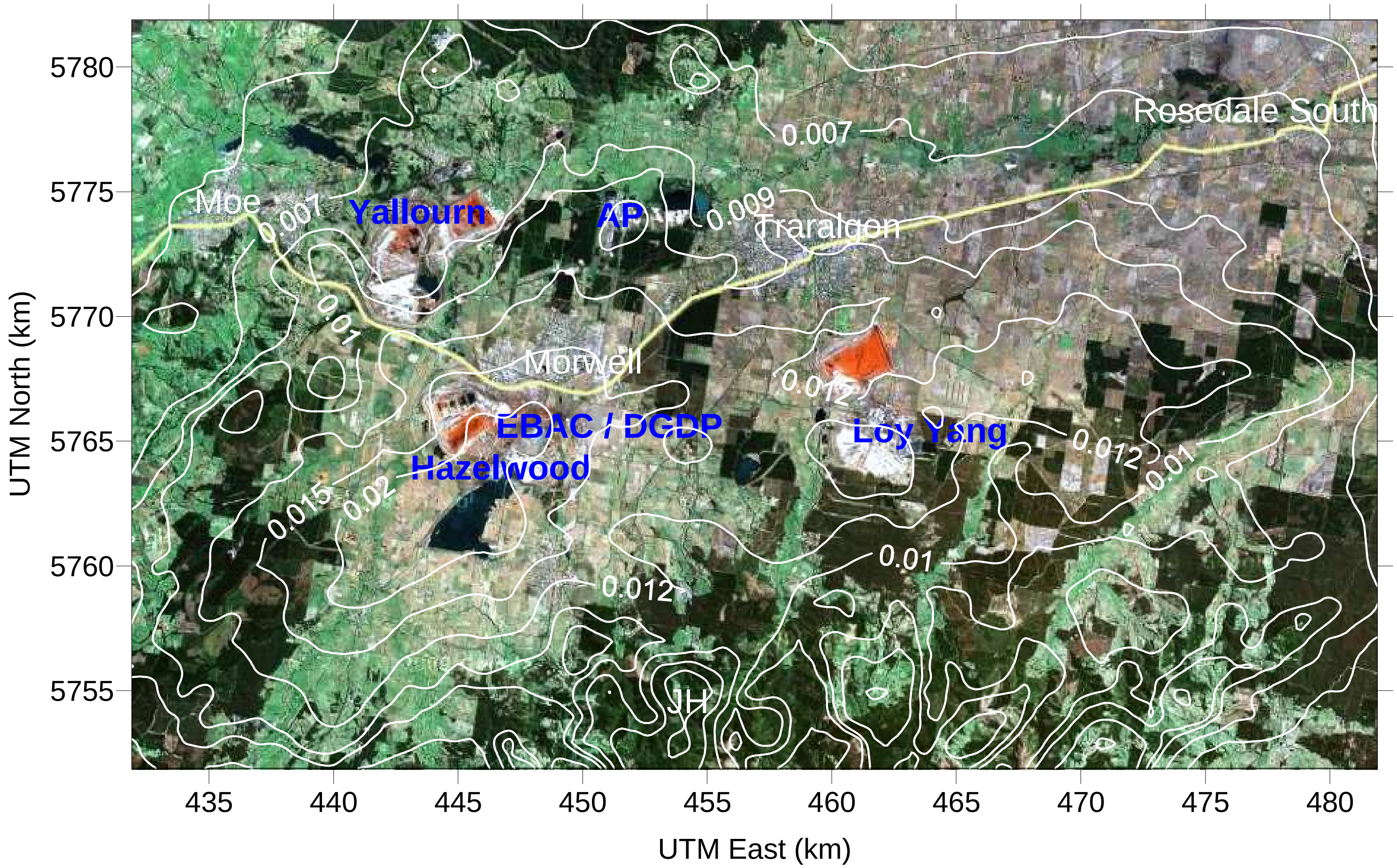


Figure C15. Validation modelling utilising CALPUFF, 1991 meteorological data and NPI emissions for the period 1 July 2007 to 30 June 2008. 99.9th percentile 1-hour NO_2 ground-level concentration contours (ppm) from Latrobe Valley power generation sources for a 1-year simulation period. Modelled 99.9th percentile 1-hour value at Moe and Traralgon monitoring stations = 0.006ppm and 0.01ppm respectively.

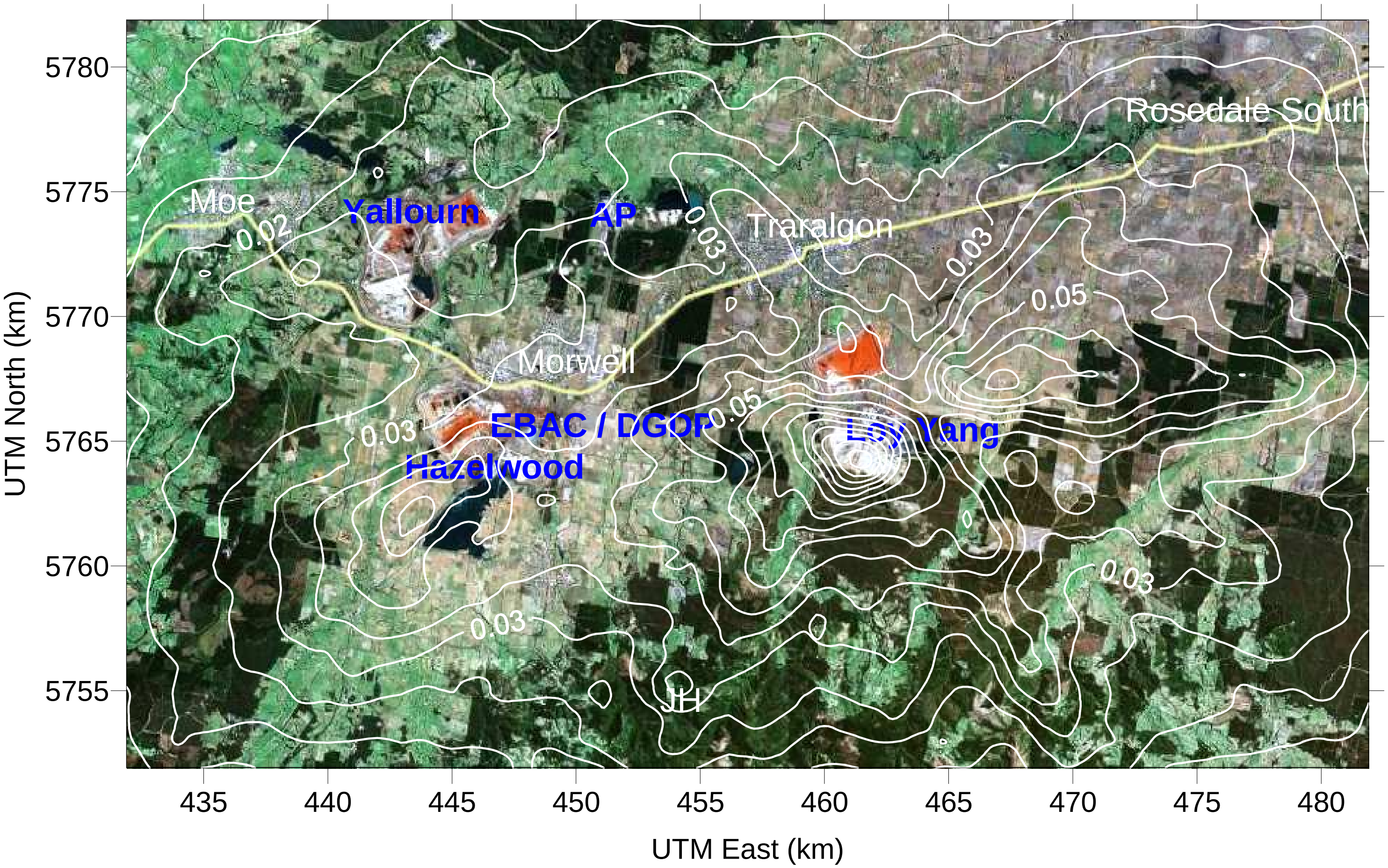


Figure C16. Validation modelling utilising CALPUFF, 1991 meteorological data and NPI emissions for the period 1 July 2007 to 30 June 2008. 99.9th percentile 1-hour SO_2 ground-level concentration contours (ppm) from Latrobe Valley power generation sources for a 1-year simulation period. Modelled 99.9th percentile 1-hour value at Moe and Traralgon monitoring stations = 0.019ppm and 0.033ppm respectively.

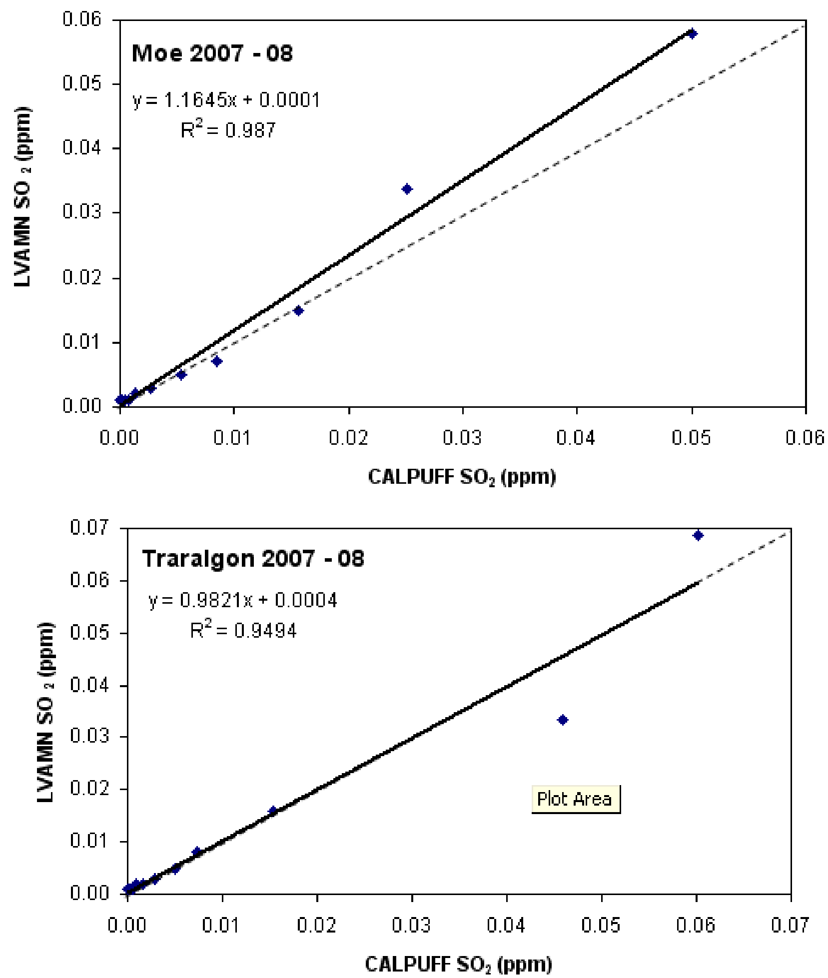


Figure C17. Validation modelling: Quality of the fit of the modelled (CALPUFF) percentile distribution of concentrations to the observed (LVAMN) percentile distribution of concentrations for SO_2 at Moe and Traralgon, utilising 1991 meteorological data and NPI emissions for the period 1 July 2007 to 30 June 2008. Dashed line is 1-1 line and solid line is linear regression line.

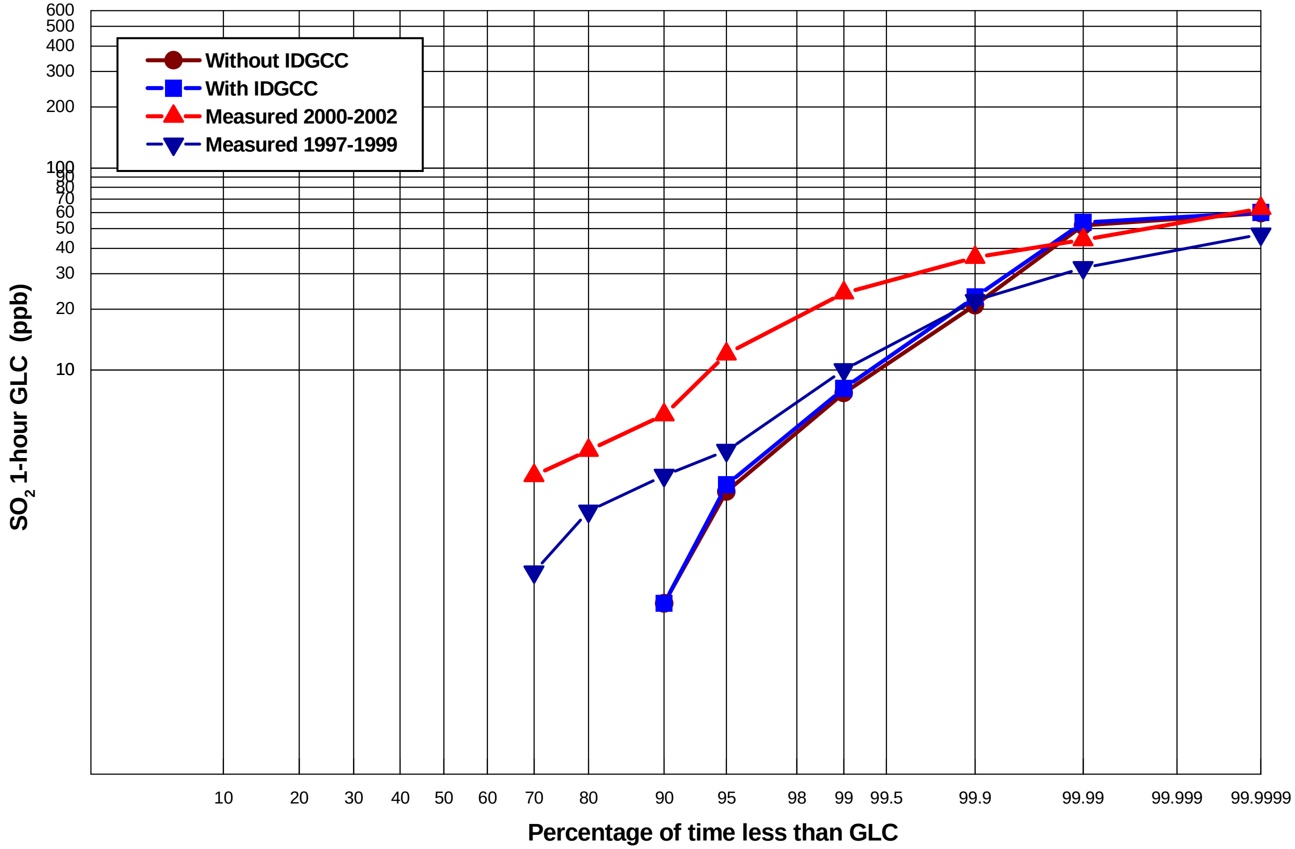


Figure C18. Validation: Moe Air Quality Station - Probability distributions of measured and predicted 1-hour SO_2 concentrations (Source: Delaney, 2007b).

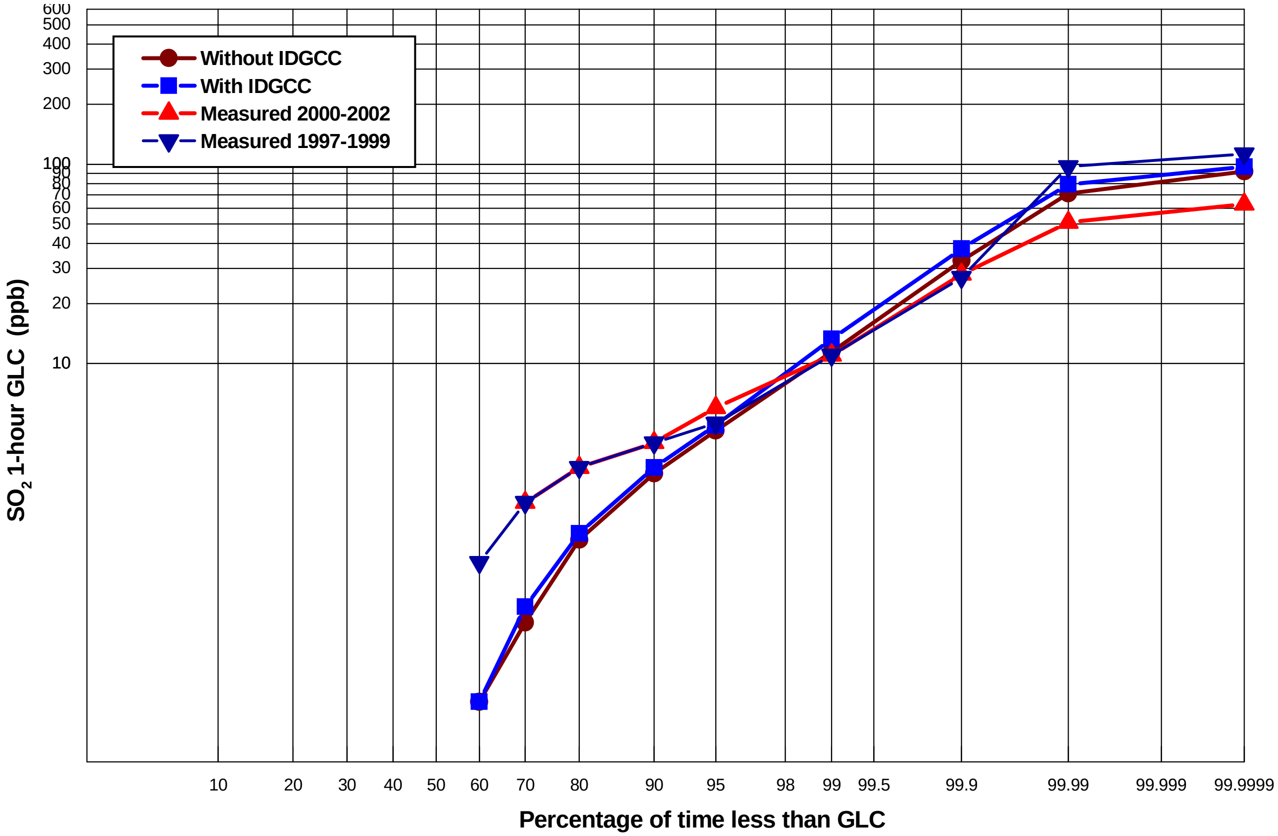


Figure C19. Validation: Traralgon Air Quality Station - Probability distributions of measured and predicted 1-hour SO_2 concentrations (Source: Delaney, 2007b).

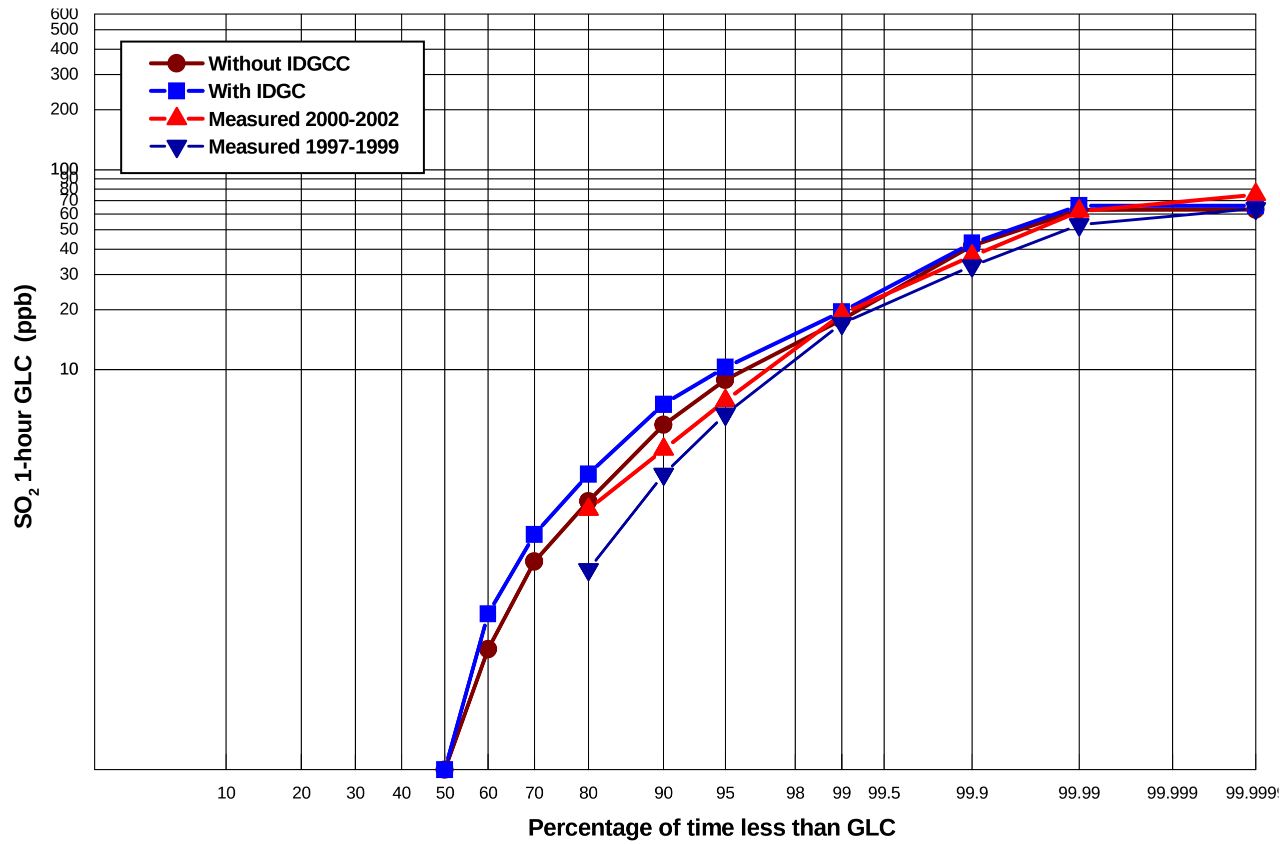


Figure C20. Validation: Rosedale South Air Quality Station - Probability distributions of measured and predicted 1-hour SO_2 concentrations (Source: Delaney, 2007b).

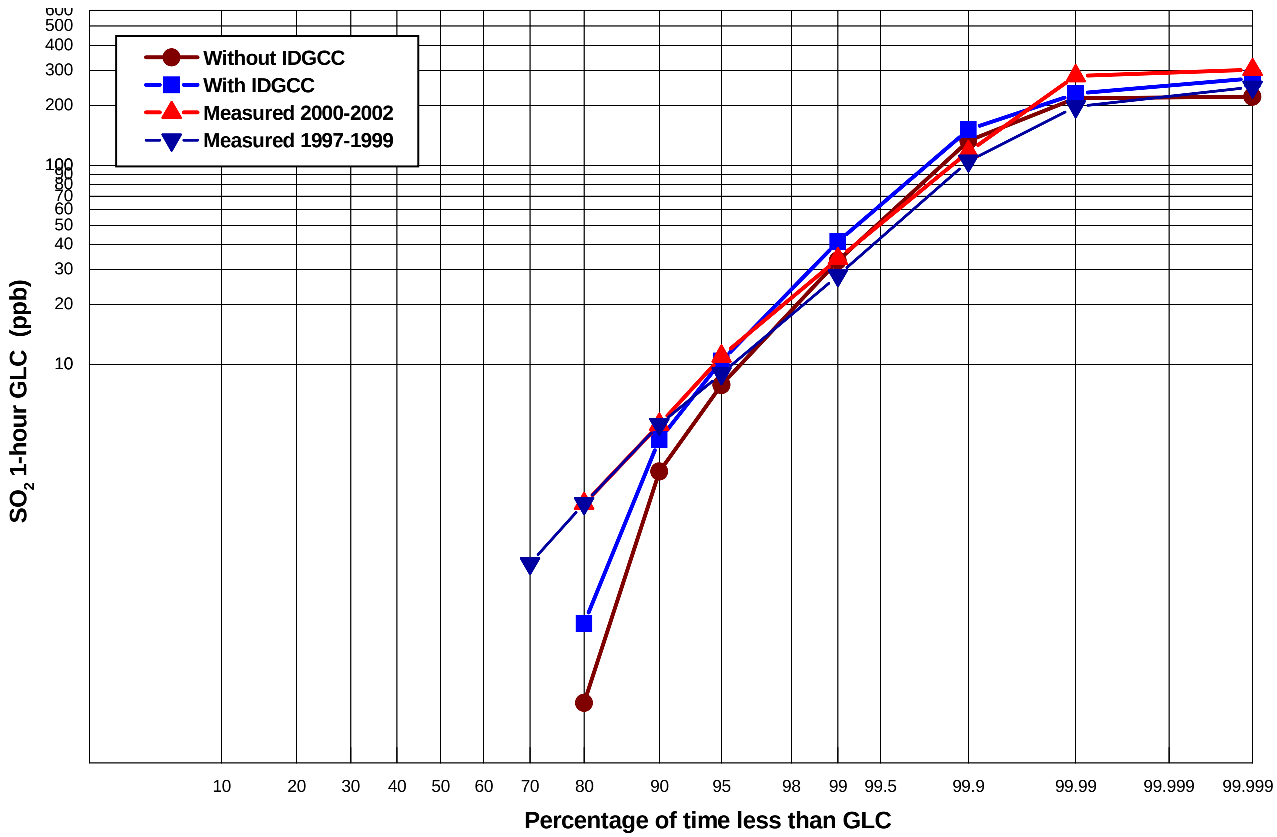


Figure C21. Validation: Jeeralang Hill Air Quality Station - Probability distributions of measured and predicted 1-hour SO_2 concentrations (Source: Delaney, 2007b).

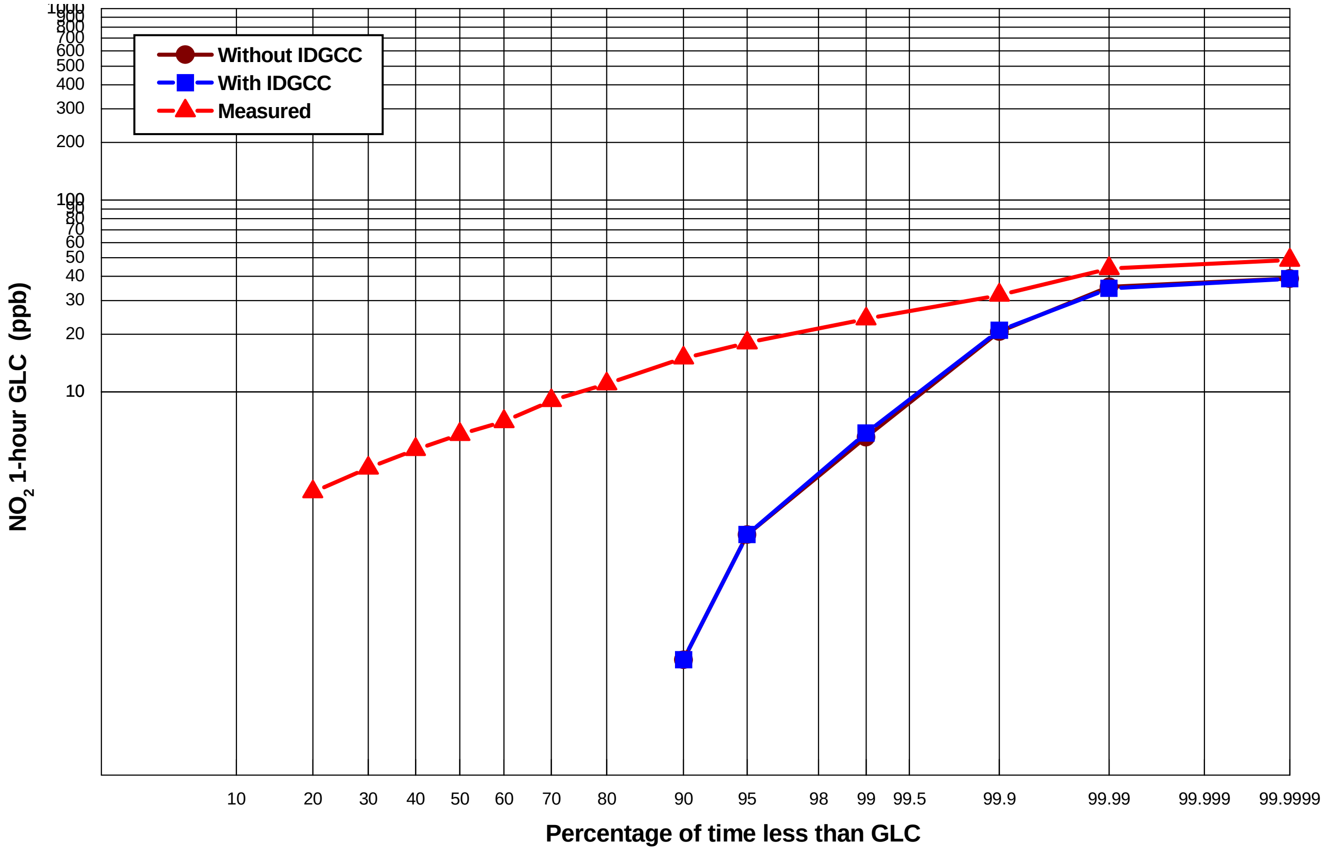


Figure C22. Validation: Moe Air Quality Station - Probability distributions of measured and predicted 1-hour NO_2 concentrations (Source: Delaney, 2007b).

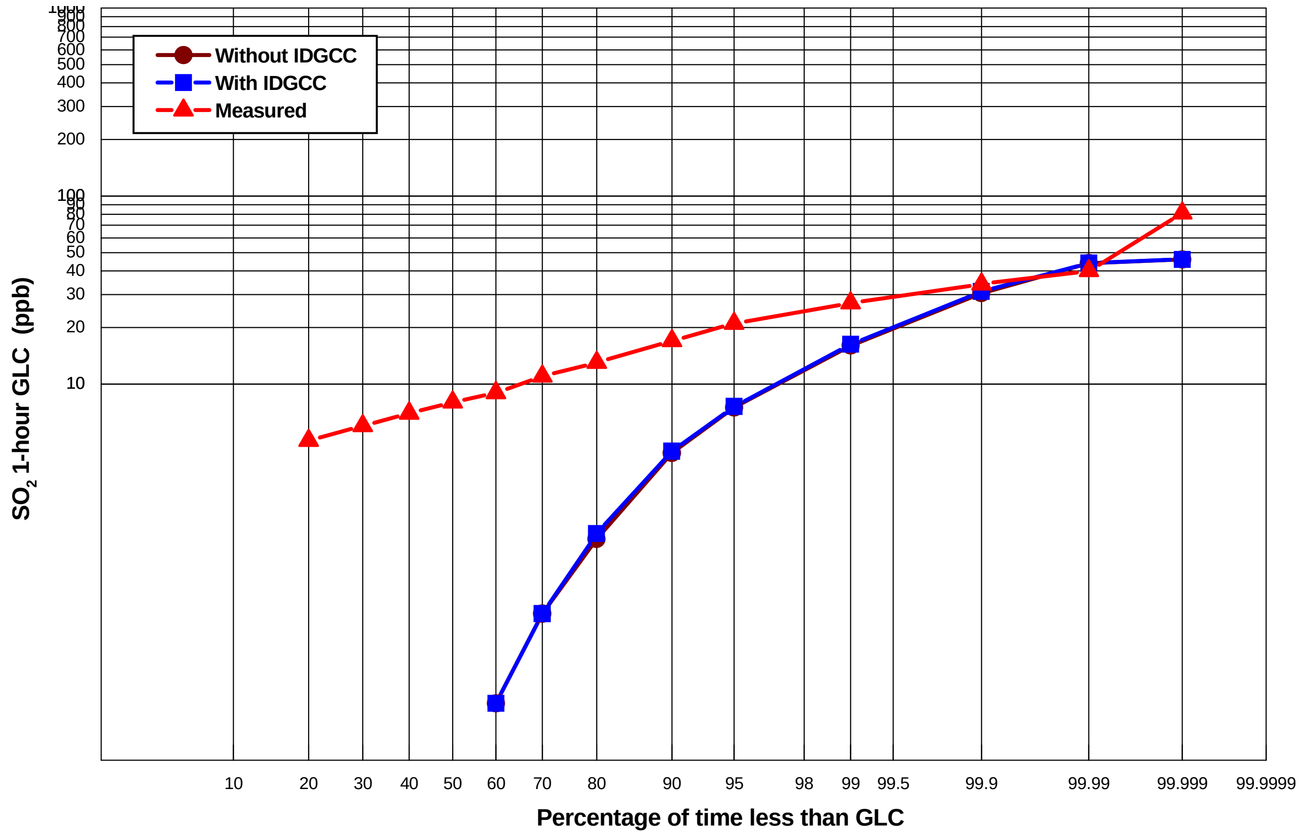


Figure C23. Validation: Traralgon Air Quality Station - Probability distributions of measured and predicted 1-hour NO_2 concentrations (Source: Delaney, 2007b).

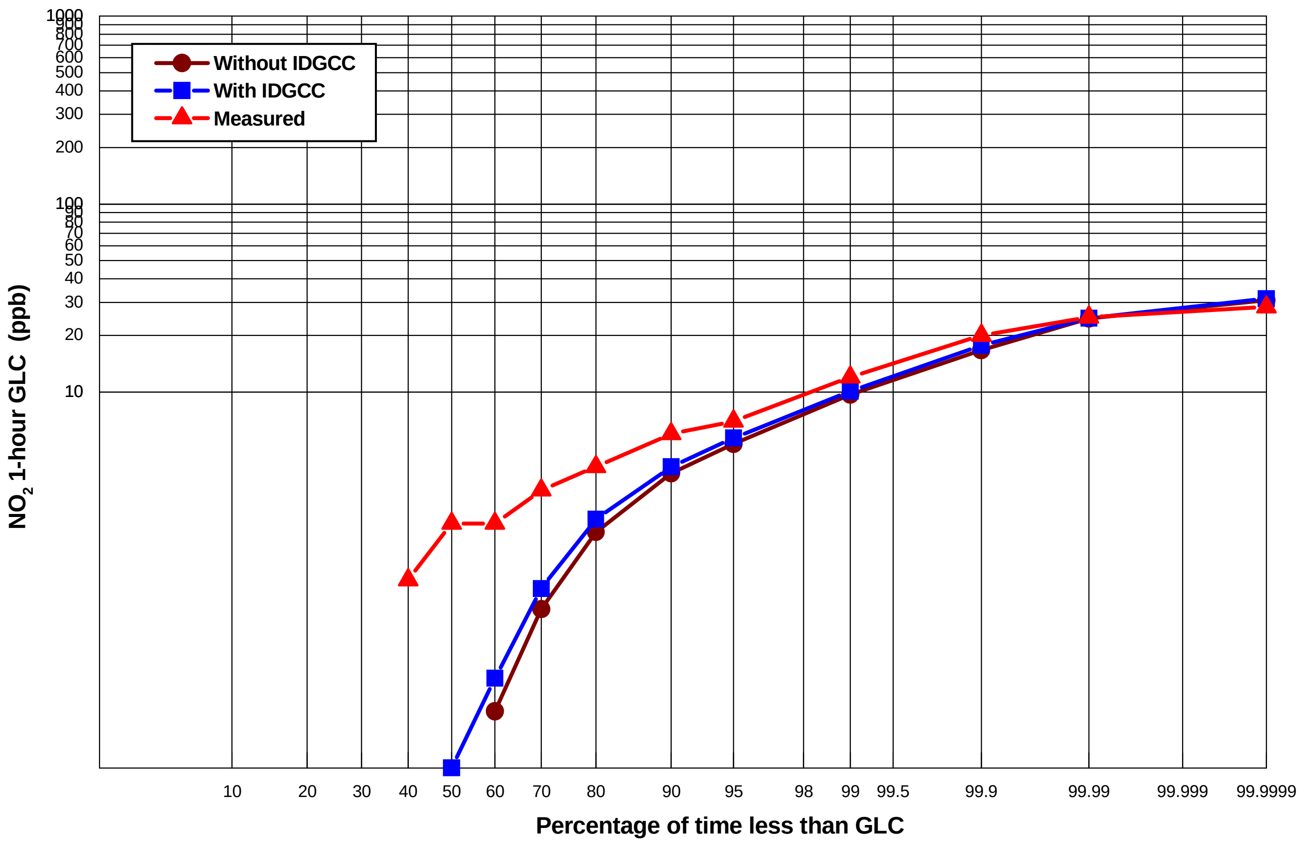


Figure C24. Validation: Rosedale South Air Quality Station - Probability distributions of measured and predicted 1-hour NO_2 concentrations (Source: Delaney, 2007b).

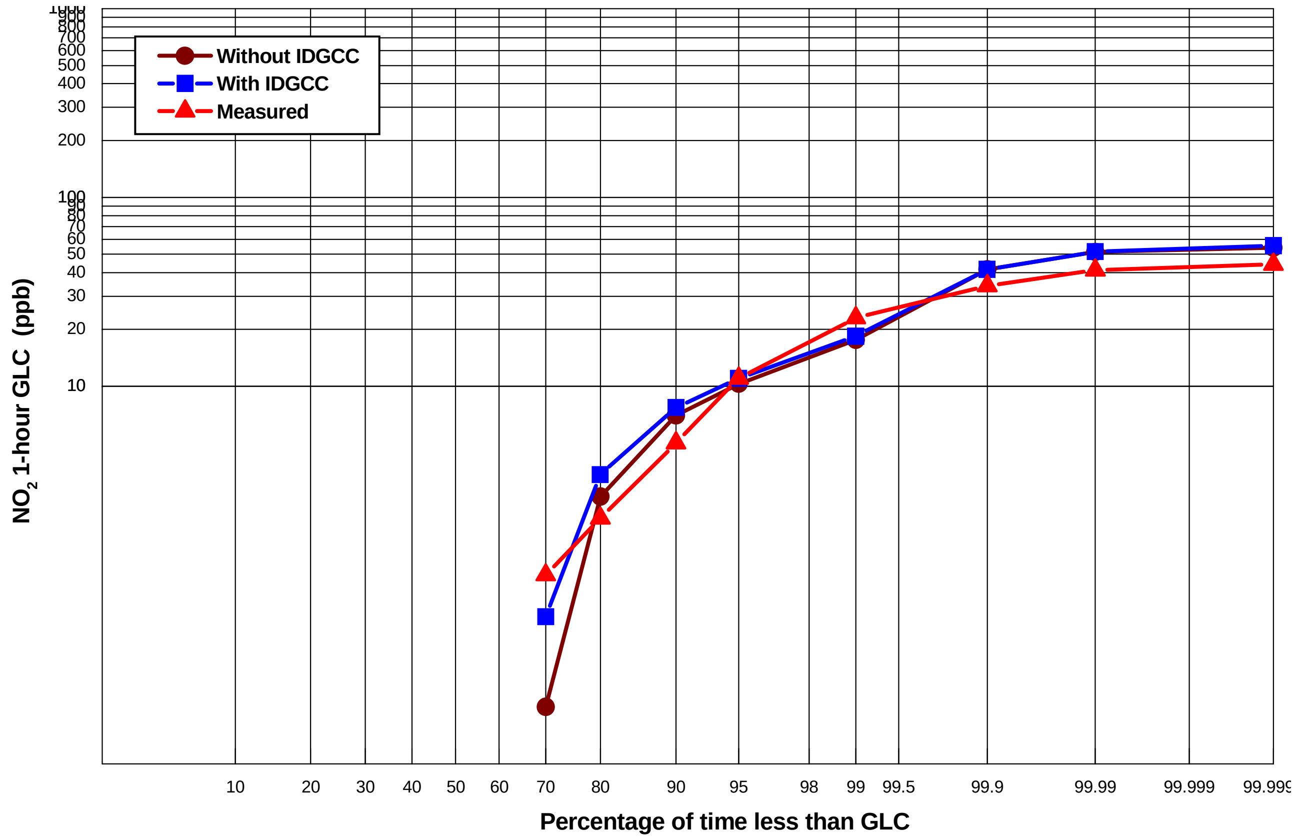


Figure C25. Validation: Jeeralang Hill Air Quality Station - Probability distributions of measured and predicted 1-hour NO_2 concentrations (Source: Delaney, 2007b).

APPENDIX D Spatial distribution – concentration contour plots

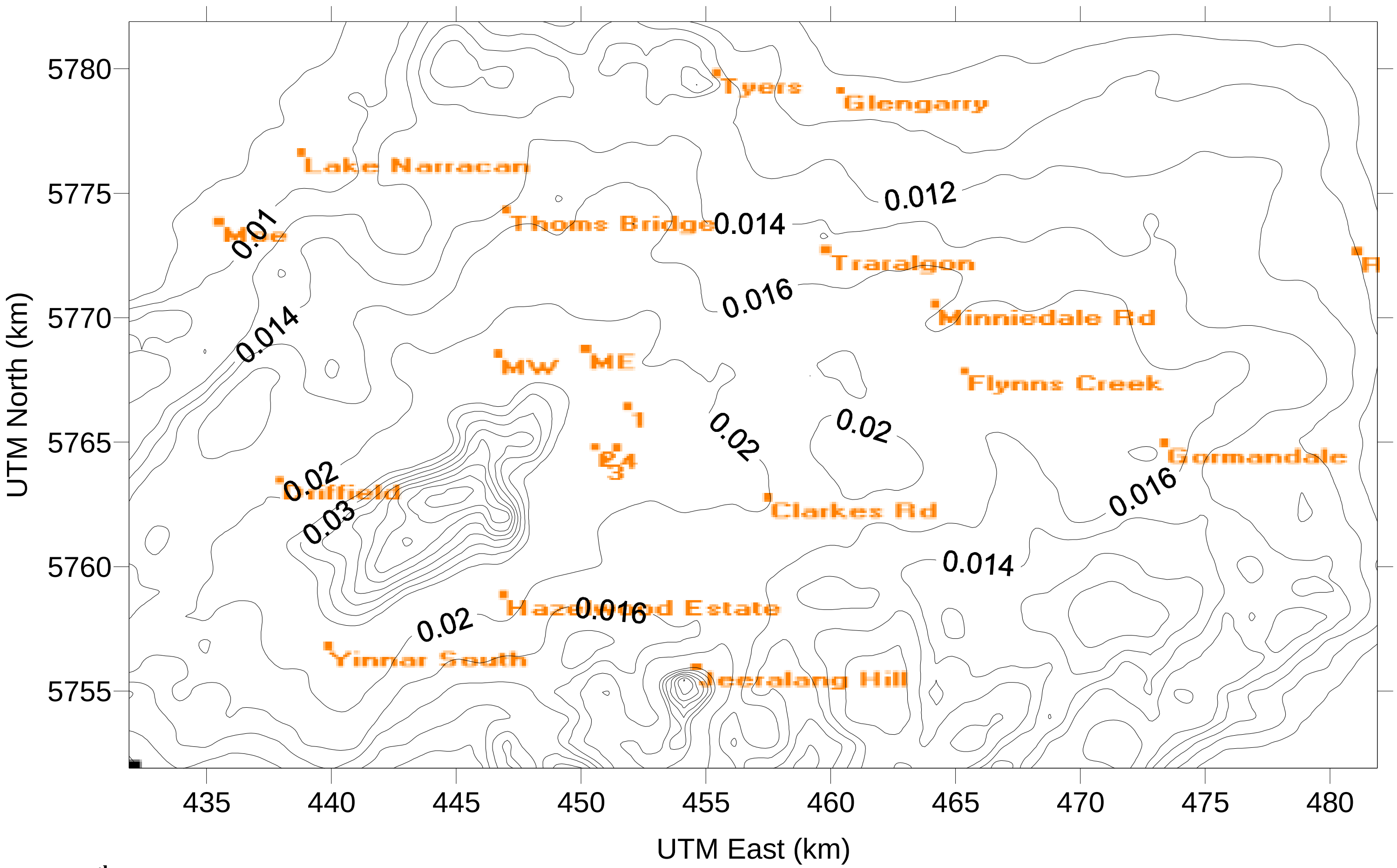


Figure D1. **99.9th percentile 1-hour NO_2 ground-level concentration (ppm) contours and discrete receptor locations – Dual Gas Demonstration Project plus other Latrobe Valley sources for a 1-year simulation period. 1-hour NO_2 Design Criteria = 0.10ppm. Modelled value (30% of total NOx) = 0.05ppm at 446.9, 5761.9.**

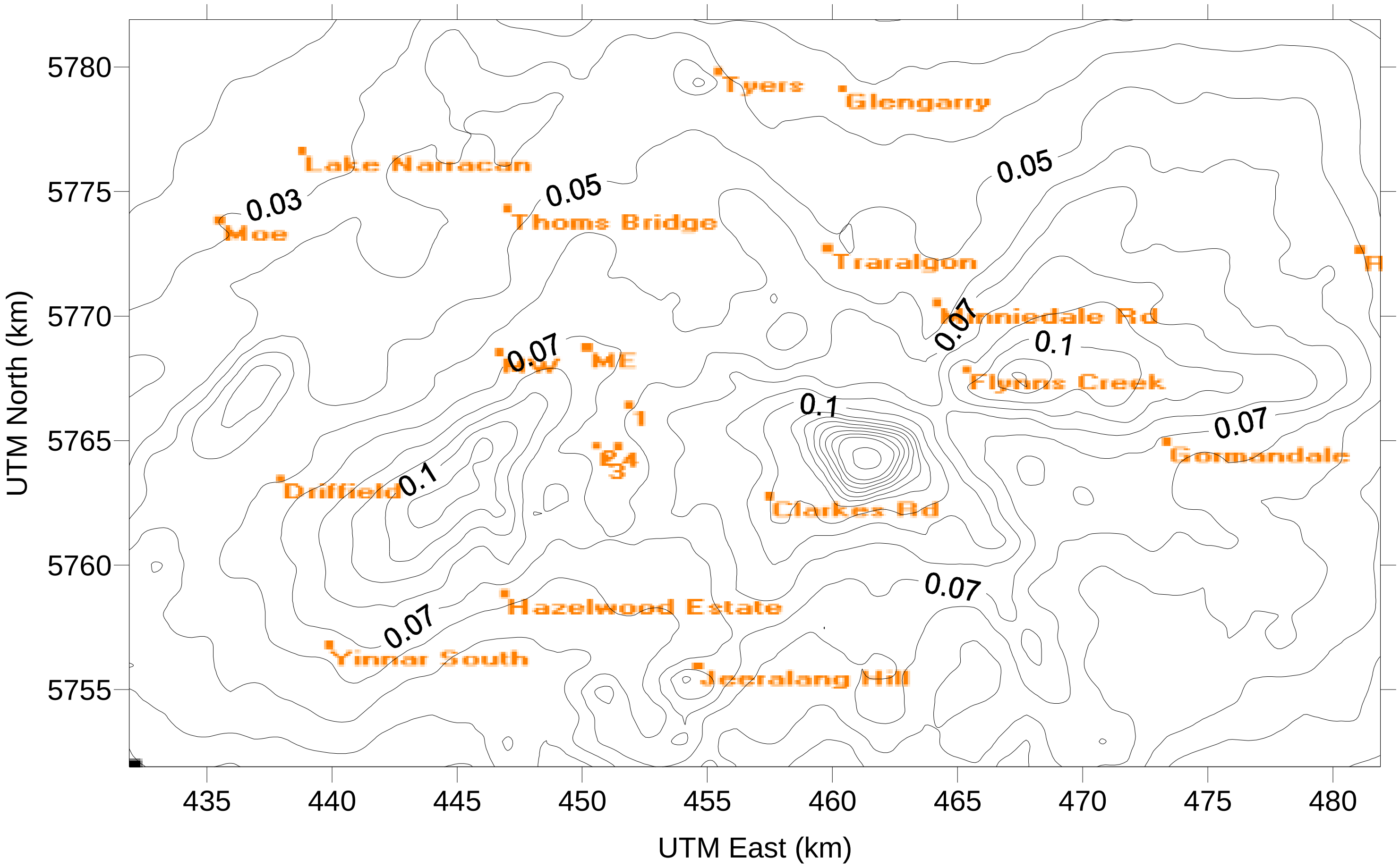


Figure D2. **99.9th percentile 1-hour SO_2 ground-level concentration (ppm) contours and discrete receptor locations – Dual Gas Demonstration Project plus other Latrobe Valley sources for a 1-year simulation period. 1-hour SO_2 Design Criteria = 0.17ppm. Modelled value = 0.15ppm at 461.9, 5763.9.**

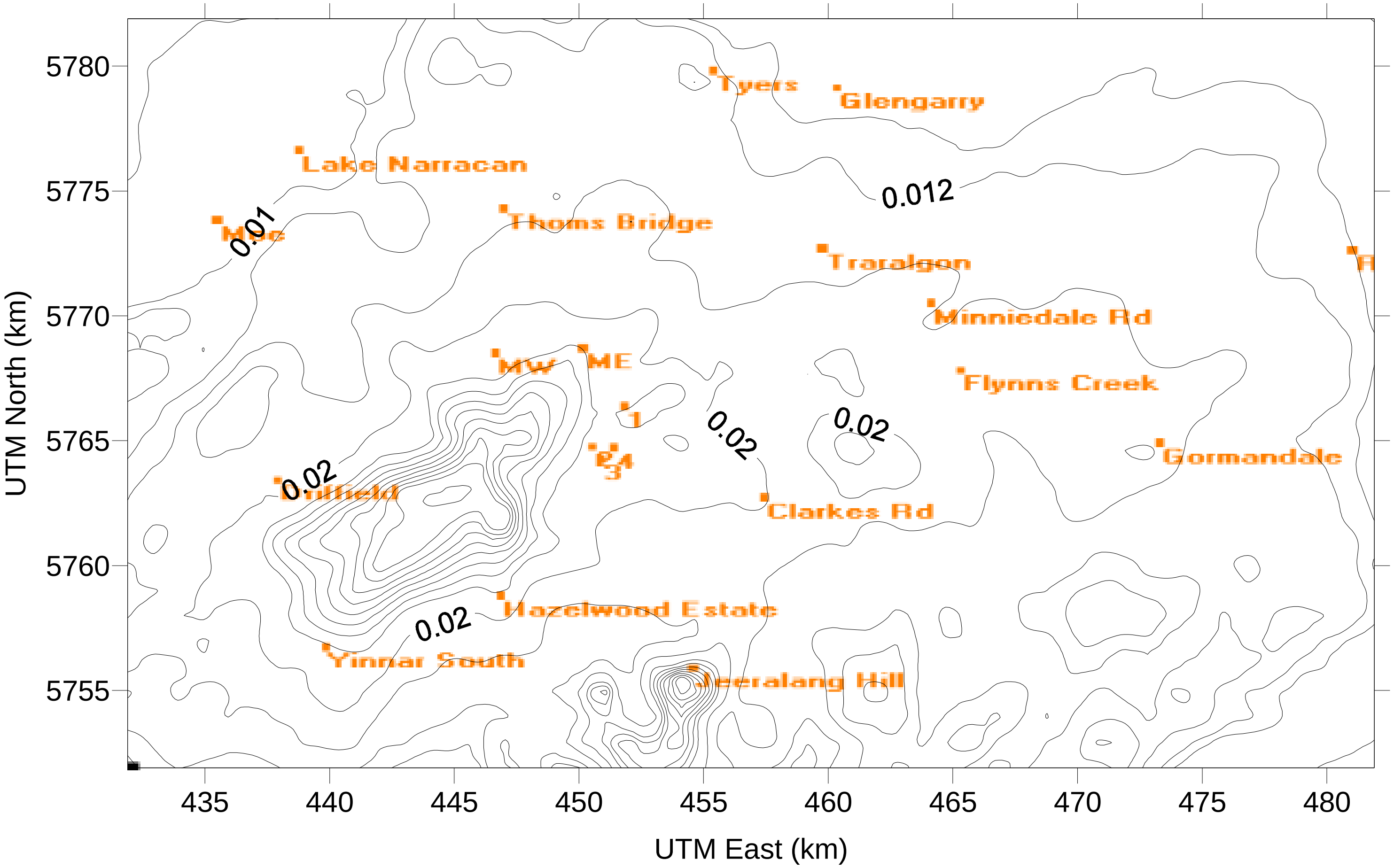


Figure D3. **99.9th percentile 1-hour NO_2 ground-level concentration (ppm) contours and discrete receptor locations – Dual Gas Demonstration Project 100% natural gas operation plus other Latrobe Valley sources for a 1-year simulation period. 1-hour NO_2 Design Criteria = 0.10ppm. Modelled value (30% of total NOx) = 0.05ppm at 446.9, 5761.9.**

Appendix D Greenhouse Gas Assessment

SINCLAIR KNIGHT MERZ
SKM

Dual Gas Demonstration Project

GREENHOUSE GAS ASSESSMENT

- FINAL
- 1 September 2010

Dual Gas Demonstration Project

GREENHOUSE GAS ASSESSMENT

- FINAL
- 1 September 2010

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Executive Summary

Dual Gas Pty Ltd (DGPL) commissioned Sinclair Knight Merz (SKM) to undertake a Greenhouse Gas Assessment to form part of the Works Approval Application for the Dual Gas Demonstration Project (DGDP). This report provides the results of that assessment.

It is expected that the proposed Dual Gas Demonstration Power Station (DGDPS) will generate approximately 600 MW of electrical power and will demonstrate the Integrated Drying and Gasification Combined Cycle (IDGCC) technology at commercial scale. The proposed DGDPS is located within the existing Energy Brix Australia Corporation site at Morwell, in Victoria.

The DGDPS does not use conventional brown coal-fired power station technology.

The DGDPS design includes two Integrated Drying and Gasification units, or ‘gasifiers’, to provide synthesis gas (syngas) to fuel two Combined Cycle Gas Turbines. It is fuelled by syngas generated from brown coal, with hydrogen gas the main energy component of syngas. Methane is the main energy component for natural gas. Natural gas will be used as a start-up and supplementary fuel for the DGDPS and normal operations by the DGDPS will include some use of natural gas.

This assessment has focussed on the average greenhouse gas emissions performance over the projected 30-year life of the DGDPS.

The exact amounts of coal and natural gas used each year will be influenced by the nature and structure of long term fuel supply contracts, electricity supply contracts, spot (short term) gas costs and electricity prices, and any cost placed on carbon emissions. Electricity prices will be influenced by electricity demand and supply (including plant retirements) and government policy.

Four case study operating scenarios have been modelled for the DGDPS covering the expected range of emissions performance for the facility on an as generated basis. The cases are described, including fuel usage details, in the following table and cover a range of potential syngas and natural gas fuel mix scenarios. Cases 1-3 are IDGCC success scenarios and Case 4 is an IDGCC non-success scenario. The expectation is that the DGDPS will commence using one gasifier in 2013 and that a second gasifier will be added in 2015. The second gasifier will incorporate lessons learned from the first gasifier.

SKM

DGDPS Operating Scenario	Coal Source and Syngas Usage	Natural Gas Usage	Average annual GHG Emissions (kt CO_2-e p.a.)	Project Average GHG Intensity 'as generated' (t CO_2-e / MWh)
Case 1	Two gasifiers fuelled by: • MOC syngas from 2012/13–2015/16 • YNX syngas from 2016/17 to 2026/27 • MOC syngas from 2027/28–2041/42	A large amount of NG used throughout lifetime.	3,024	0.73
	Average coal usage: 2,345 kT p.a.	Average 11,425 TJ p.a.		
Case 2	Two gasifiers fuelled by: • MOC syngas from 2012/13–2015/16 • YNX syngas from 2016/17 to 2026/27 • MOC syngas from 2027/28–2041/42	A moderate amount of NG throughout lifetime.	3,201	0.77
	Average coal usage 2,636 kT p.a.	Average 8,715 TJ p.a.		
Case 3	Two gasifiers fuelled by MOC syngas over 30-year lifetime	A moderate amount of NG throughout lifetime.	3,238	0.78
	Average coal usage 2,803 kT p.a.	Average 9,518 TJ p.a.		
Case 4 note*	MOC syngas-fuelled by single gasifier ceasing after 4 years in 2015/16	DGDPS fuelled by NG only from 2016/17–2041/42.	762	0.45
	MOC coal usage average 322 kT p.a. (average of first 4 years only)	Average 14,108 TJ p.a.		

Note* In the event that the IDGCC technology is found to be unfeasible (at commercial scale), after approximately the first four years, the facility would revert to be wholly natural gas fired with a corresponding lower GGI of approximately 0.43 t CO_2-e / MWh.

The flexibility of the DGDPS, allowing the use of lower greenhouse intensive natural gas as well as the abundant and (currently) lower cost brown coal, avoids the potential of an emissions lock-in for the 30-year plus project.

The average greenhouse gas emission for the three IDGCC success scenarios (Cases 1 – 3), over the DGDPS's 30-year life, is expected to range between 3.0 – 3.2 million tonnes of carbon dioxide equivalent (Mt CO_2-e) per annum.

The theoretical maximum greenhouse gas emission for the proposed DGDPS is calculated to be 4.2 million tonnes of carbon dioxide equivalent (Mt CO_2-e) per annum, however is very unlikely to occur given expected normal operating and market conditions.

This assessment has found that, for the three DGDPS success scenarios studied, on an annual basis over its projected 30-year life the DGDPS greenhouse gas intensity is expected to range between 0.73 – 0.78 t CO_2-e / MWh, depending on the fuel mix.

The Victorian Government's *Victorian Climate Change White Paper - The Action Plan*, (July 2010), sets a target greenhouse gas intensity of 0.8 t CO_2-e / MWh for new power stations. The DGDPS's emissions performance complies with this benchmark.

Comparison of DGDPS performance against existing power stations and 'best practice' power generation technology, is determined using publicly available GGI data on a 'sent out' basis and calculating a 'generated' GGI using an estimate for electricity consumed by the power station.

The greenhouse gas intensities for the larger brown coal-fuelled power stations in the Latrobe Valley are listed below (there are slight variations from year-to-year):

Power Station	Greenhouse Gas Intensity (t CO_2-e / MWh "Sent Out")	Estimated Electricity Percentage Used Internally	Greenhouse Gas Intensity (t CO_2-e / MWh "Generated"
Hazelwood Power Station	1.52	8 %	1.40
Yallourn Power Station	1.42	8 %	1.31
Loy Yang A	1.21	7 %	1.12
Loy Yang B	1.23	7 %	1.14

This assessment has found that the proposed DGDPS success cases studied will have greenhouse gas intensities significantly less (31% - 36%) than the best current brown coal power station (Loy Yang A) with variations depending on the coal quality and amounts of syngas and natural gas used by DGDPS each year.

Clearly, comparisons of the DGDPS GGIs with those of the existing brown coal power stations (listed above) show that the DGDPS will offer significantly better GGIs than the best current sub-critical brown coal fired power station in the Latrobe Valley.

Also, the DGDPS is expected to exceed the performance standard for 'supercritical brown coal'; *i.e.*, 0.98 t CO_2-e / MWh (AGO, 2006).

The DGDPS is expected to have a lower project average GGI than all existing black coal power stations in Australia.

The DGDPS provides a technology pathway for lower emissions from brown coal.

The DGDPS has been designed to enable the potential retrofit of CO_2 capture technology when commercially viable. The proposed site layout includes space reserved for the potential carbon capture plant to be located. The retro-fitting of carbon capture technology is expected to lower the GGI to well below best practice natural gas combined cycle.

HRL has estimated the current annual CO_2-e emissions of Latrobe Valley brown coal-fired power stations to be approximately 57 Mt per annum. If new IDGCC technology with a GGI of 0.73 t CO_2-e / MWh was to displace the current fleet of brown coal power stations, this would result in annual savings of approximately 24 Mt of CO_2-e emissions per annum (a 42% reduction in these emissions in the Latrobe Valley). HRL estimates that a further savings of approximately 21 Mt per annum would be achieved with the development and implementation of carbon capture and storage technologies. The total annual savings of 45 Mt CO_2-e would equate to 8.3% of the total Australian CO_2 emissions (based on 2007 data).

In conclusion, with respect to the need to reduce greenhouse gas emissions, this assessment has found that the proposed DGDPS represents a markedly improved technology for producing electricity from brown coal. The improvement is due to integrated drying and gasification of brown coal allowing for improved brown coal emissions performance, supplemented by the lower emissions performance of natural gas. It also provides a future technology development pathway for lower CO_2 emissions performance for the generation of power from brown coal.

Acronyms & Definitions

AGO	Australian Greenhouse Office
CCGT	Combined Cycle Gas Turbine
CH_4	Methane
CO_2	Carbon dioxide
DCCEE	Department of Climate Change and Energy Efficiency
EPA	Environment Protection Authority (Victoria)
DGDP	Dual Gas Demonstration Project
DGDPS	Dual Gas Demonstration Power Station
DGPL	Dual Gas Pty Ltd
EBAC	Energy Brix Australia Corporation
GES	Generator Efficiency Standards
GGI	Greenhouse Gas (emissions) Intensity
GHG	Greenhouse Gas
GWP	Global Warming Potential
HFC	Hydrofluorocarbons
HRL	HRL Limited
HRLT	HRL Technology
IDG	Integrated (coal) Drying and Gasification
IDGCC	Integrated Drying Gasification Combined Cycle
IPCC	Intergovernmental Panel on Climate Change
MW	Megawatt
MOC	Morwell Coal
MWh	MegaWatt hour (Generated)
MWh SO	MegaWatt hour Sent Out
NGERS	National Greenhouse and Energy Reporting System
NO_x	oxides of nitrogen
NG	Natural Gas
NGA	National Greenhouse Accounts
pf	Pulverised Fuel
PFC	Perfluorocarbons
SF_6	Sulfur hexafluoride
SEPP	State Environment Protection Policy (Air Quality Management)
SKM	Sinclair Knight Merz
syngas	synthesis gas
UNFCCC	United Nations Framework Convention on Climate Change
YNX	Yallourn North Extension Coal

1. Introduction

1.1. General Introduction

Dual Gas Pty Ltd (DGPL) commissioned Sinclair Knight Merz (SKM) to undertake a Works Approval Assessment for a proposed approximate 600 MW demonstration power station using Integrated Drying and Gasification Combined Cycle (IDGCC) technology at Morwell, Victoria.

The proposed demonstration power station and associated infrastructure, including approximately four kilometres of 500kV transmission line to connect the demonstration power station and the existing Hazelwood Terminal Station, is known as the Dual Gas Demonstration Project (DGDP).

DGDP will be the first application of IDGCC technology at commercial scale and will demonstrate advanced power generation technology using a combination of synthesis gas ('syngas') produced from brown coal, and Natural Gas (NG).

The proposed demonstration power station would be operated primarily as a base-load demonstration power station, with the power generated by the DGDP being sold in the National Electricity Market.

1.2. The Proponent

DGDP's proponent is DGPL, a special-purpose company created by HRL to build, own and operate the Dual Gas Demonstration Power Station (DGDPS). HRL Limited (HRL) is an Australian owned energy, technology and project development company. Within HRL's group of companies, HRL Technology (HRLT) provides consulting and testing services to the coal, energy and engineering industries.

1.3. Description of Dual Gas Demonstration Power Station

DGPL is proposing to build the DGDPS within the existing boundaries of the Energy Brix Australia Corporation (EBAC) facility in the Latrobe Valley, south of the township of Morwell.

The proposed DGDPS will include the following equipment:

- 2 integrated drying and gasification plants including: Syngas filtration and conditioning plant; Air compressors; Char and ash combustion plant; and By-product drying and crystallisation plant.
- 2 gas turbines (GTs); 2 heat recovery steam generators (HRSGs); 1 steam turbine and generator (STG); and
- 1 air cooled condenser (ACC).

The primary fuels used in the power generation are expected to be syngas (produced from brown coal), and NG with the latter used as a supplementary and start-up fuel. A range of fuel usage options has been assessed with respect to the syngas-NG mix.

1.4. Study Objectives

The main objectives of this study are to meet the requirements of the *State Environment Protection Policy (Air Quality Management)* (SEPP, 2001) and the *Protocol for Environmental Management – Greenhouse gas emissions and energy efficiency in industry* (PEM); see EPAV (2002) and EPAV (2006).

The study aims to provide the necessary information supporting the Works Approval Assessment; in general, this includes discussion and assessment of:

- Issues associated with energy use and greenhouse gases;
- State and Federal Government commitments and response to the management of greenhouse gases as detailed in National and International policy;
- Expected greenhouse gas emissions from the proposed demonstration power station; and
- Implementation of 'best practice' with respect to GHG emissions and energy consumption.

2. Greenhouse Gases and Climate Change

2.1. Overview

This section of the report sets out issues associated with the science of greenhouse gases (GHGs) and climate change.

2.2. Definition: Global Warming Potential

Global warming potentials (GWPs) are used to compare the abilities of different GHGs to trap heat in the atmosphere. GWPs are based on the radiative efficiency (heat-absorbing ability) of each gas relative to that of CO_2, as well as the effective lifetime of each gas relative to that of CO_2. The GWP provides a means to convert emissions of various gases into a common measure, which is denoted as carbon dioxide equivalent (CO_2-e).

The generally-accepted authority on GWPs is the Intergovernmental Panel on Climate Change (IPCC); *e.g.*, refer to Solomon *et al.* (2007). The IPCC regularly updates its estimates of GWPs for key GHGs. **Table 2-1** compares the GWPs published by the IPCC in 1996, 2001 and 2006. It is noted that reporting under the Kyoto Protocol (refer to **Section 3.2.2**), is based on the 1996 IPCC GWPs.

- **Table 2-1 Comparison of 100-Year GWP Estimates**

Greenhouse Gas	1996 IPCC GWP	2001 IPCC GWP	2006 IPCC GWP
Carbon Dioxide (CO_2)	1	1	1
Methane (CH_4)	21	23	25
Nitrous Oxide (N_2O)	310	296	298
HFC-23	11,700	12,000	14,800
HFC-125	2,800	3,400	3,500
HFC-134a	1,300	1,300	1,430
HFC-143a	3,800	4,300	4,470
HFC-152a	140	120	124
HFC-227ea	2,900	3,500	3,220
HFC-236fa	6,300	9,400	9,810
Perfluoromethane (CF_4)	6,500	5,700	7,390
Perfluoroethane (C_2F_6)	9,200	11,900	12,200
Sulphur Hexafluoride (SF_6)	23,900	22,200	22,800

Sources: IPCC's Second (1996), Third (2001) and Fourth (2006) Assessment Reports.

As shown above, the latest GWP for CH_4 is 25, and for N_2O, 298. This means that emissions of 1 tonne of CH_4 and N_2O are respectively equivalent to emissions of 25 and 298 tonnes of CO_2 (t CO_2-e).

2.3. Major Anthropogenic Greenhouse Gases

This sub-section provides brief descriptions of the major GHGs produced or influenced by human activities: Carbon dioxide (CO_2); Methane (CH_4); Nitrous oxide (N_2O); Synthetic halocarbons; Sulfur hexafluoride (SF_6); and some other gases.

Carbon dioxide is the main anthropogenic gas contributing to climate change, responsible for approximately 63% of the warming associated with climate change. Concentrations of this gas in the atmosphere have increased by approximately 36% during the past 200 years, from 280ppm in the 1700s to 370ppm in 2005, with concentrations increasing at a progressively faster rate each decade–the average growth rate of CO_2 emissions increased from 1.1% per year in the 1990s to a 3% increase per year in the 2000s (Raupach *et al.*, 2007). The major anthropogenic sources of CO_2 emissions are fossil fuel combustion and land clearing for agriculture.

Atmospheric methane concentrations have increased by 150% during the past 200 years. While atmospheric methane concentrations remained relatively constant over the past decade, recent monitoring results from CSIRO and others indicate that concentrations showed renewed growth from the beginning of 2007 (Rigby *et al.*, 2008), possibly caused by increases in emissions in the Northern Hemisphere.

Although there is a lower proportion of CH_4 in the atmosphere than CO_2, CH_4 has a significantly higher GWP. The major sources of CH_4 are cattle, rice growing and leakages during natural gas production, distribution and use. While natural processes currently remove CH_4 from the atmosphere at almost the same rate as it is being added, CH_4 concentrations are likely to rise over the next 100 years.

Atmospheric nitrous oxide concentrations have increased by 15% during the past 200 years and the gas can persist in the atmosphere for up to 100 years. Major sources of nitrous oxide include industrial processes, fertiliser use and other agricultural activities, including land clearing.

Halocarbons are chemicals that contain carbon atoms linked with one or more halogen atoms (fluorine, chlorine, bromine or iodine). Chlorofluorocarbons (CFCs) are a type of halocarbon, and formerly had widespread use as refrigerants before they were found to deplete ozone levels in the upper atmosphere. Hydrofluorocarbons (HFCs) were introduced to replace CFCs in the refrigerant industry since they do not deplete ozone as they contain no chlorine. HFCs, however, can have GWPs more than 11,000 times that of CO_2, and are targeted under the Kyoto Protocol together with another class of halocarbon, perfluorocarbons (PFCs). As technologies currently exist to reduce emissions of these gases to near zero over the next few decades, they represent probably the most significant, immediate opportunity to slow down the current growth of GHGs in the atmosphere.

Sulfur hexafluoride is a synthetic gas; the gas has no odour, smell or taste, and is non-combustible and chemically inert at room temperature. The Greenhouse Challenge Discussion Paper *Sulfur Hexafluoride and the Electricity Supply Industry*, issued by the Australian Greenhouse Office in 2001, states that SF_6 emissions can occur from its use in metal processing and the electricity supply industry. While the quantities of emissions of this gas are currently comparatively small to those generated during the combustion of fossil fuels, its GWP is 23,900 times that of carbon dioxide.

The main use of SF_6 globally is in electricity transmission and distribution, which accounts for approximately 80 per cent of use. These industries use SF_6 for electrical insulation, arc quenching, and current interruption in equipment used in the transmission and distribution of electricity. Most of the SF_6used in the electrical equipment is used in gas insulated switchgear and circuit breakers, although some SF_6 is used in high voltage gas-insulated transmission lines and other equipment. International data suggested that handling losses results in 80 to 85% of all SF_6 emissions from the electricity supply industry, with leakages from equipment representing between 15 and 20% of emissions.

Other greenhouse gases include the hydroxyl radical (OH), a highly reactive agent that helps to cleanse the atmosphere of pollutants such as methane. OH will also react with carbon monoxide which, although not a GHG, reduces the amount of OH in the atmosphere, thereby increasing the length of time GHGs such as methane stay in the atmosphere. Carbon monoxide, hydrocarbons and oxides of nitrogen can react to form ozone, another GHG. Tropospheric ozone acts as an effective GHG.

2.4. The Greenhouse Effect and Climate Change

Solar radiation incident on the lower more dense part of the atmosphere, the troposphere, is scattered and absorbed by air molecules, aerosols, cloud water droplets and ice crystals. The atmosphere scatters some of the incident radiation back towards space. Some of the remainder of this radiation is absorbed by the atmosphere, increasing its temperature.

The solar radiation transmitted through the atmosphere is reflected and absorbed by the earth’s ocean and land surfaces. The warm earth and atmosphere emit thermal radiation into space and back towards the earth. These solar and terrestrial radiative fluxes determine the state of the earth’s climate and the earth’s surface temperature.

Without the atmosphere the mean temperature of the earth's surface would be about -18 ^{o}C. Considering a gaseous atmosphere only, (without aerosols or clouds), the temperature of the earth’s surface would be increased to about +30^{o}C. This warming is the so-called Greenhouse Effect– caused by the absorption of terrestrial infrared radiation by trace gases in the atmosphere, mainly CO_2 and H_2O, and the re-emission of some of this energy back towards the earth.

Human activities, such as the combustion of carbon-based fuels, increase the amount of GHGs in the atmosphere, enhancing the Greenhouse Effect. The atmospheric concentration of CO_2 has risen from 280 parts per million (ppm) to 370 ppm since 1860. At the same time, the average global temperature has increased by nearly 1°C. Projections show that if this trend continues, global temperatures could rise between one and four degrees by the end of the 21st century, with annual average temperatures in Australia projected to increase by 0.4–2.0°C by 2030 and by 1–6°C by 2070 compared to 1990 levels (WBCSD, 2004).

Australia's per capita GHG emissions are among the highest in the world, being more than four times the world average, and primarily are the result of our reliance on coal-generated electricity (Garnaut, 2008).

The results of a climate change report by global risks analyst Maplecroft[1] indicated that Australia is the world's worst offender with respect to CO_2 emissions (this was widely reported in the media); some results from that report are: Australia, 20.58 ton CO_2 per person per annum (Rank 1); USA, 19.78 ton CO_2 per person p.a. (Rank 2); Canada, 18.81 ton CO_2 per person p.a. (Rank 3); with China and India on 4.5 and 1.16 ton CO_2 per person p.a. respectively, with these latter two countries usually considered two of the world's worst overall CO_2 polluters.

Climate change is widely recognised as a major global issue, with human activity and the combustion of fossil fuels increasing the atmospheric concentrations of GHGs, particularly CO_2. The build-up of GHGs in the atmosphere may lead to long-term increases in temperature causing rising sea level, changes in weather patterns, more extreme events such as droughts, floods and cyclones, and decreased water availability in some regions.

2.5. Copenhagen Diagnosis 2009: Updating IPCC's AR4

The Copenhagen Diagnosis 2009 (Allison *et al.*, 2009), updates the scientific findings provided in the Intergovernmental Panel on Climate Change (IPCC) Fourth Assessment Report (AR4); *e.g.*, Solomon *et al.* (2007). Copenhagen Diagnosis 2009 serves as an interim evaluation of the evolving science midway between AR4 and the IPCC AR5 due for completion in 2013. A summary of some of the key findings from this update provided in the following points:

- Global CO_2 emissions from fossil fuels in 2008 were nearly 40% higher than those in 1990. Even if global emission rates are stabilized at present-day levels, just 20 more years of emissions would give a 25% probability that warming exceeds 2°C.

[1] http://www.maplecroft.com/news/australia_overtakes_usa_as_top_polluter_09.php, accessed 7/5/2010.

- Over the past 25 years temperatures have increased at a rate of 0.19°C per decade, in very good agreement with predictions based on GHG increases. Even over the past ten years, despite a decrease in solar forcing, the trend continues to be one of warming. Natural, short-term fluctuations are occurring as usual, but there have been no significant changes in the underlying warming trend.
- A wide array of satellite and ice measurements now demonstrate beyond doubt that both the Greenland and Antarctic ice-sheets are losing mass at an increasing rate. Melting of glaciers and ice-caps in other parts of the world has also accelerated since 1990.
- Summer-time melting of Arctic sea-ice has accelerated far beyond the expectations of climate models. The area of sea-ice melt during 2007-2009 was about 40% greater than the average prediction from IPCC AR4 climate models.
- Satellites show recent global average sea-level rise (3.4 mm/yr over the past 15 years) to be approximately 80% above past IPCC predictions. This acceleration in sea-level rise is consistent with a doubling in contribution from melting of glaciers, ice caps, and the Greenland and West-Antarctic ice-sheets.

2.6. The Current Status and Future of Climate Science

Early in 2010 many stories were published in the world-wide media that were highly critical of the IPCC, due to weaknesses identified in the IPCC's *2007 Fourth Assessment Report* (AR4) (IPCC, 2007a). The IPCC recognised the errors identified in AR4 and actions were taken; *e.g.*, with respect to studies of Himalayan glaciers refer to IPCC (2010).

Review of the AR4 scientific reports; *e.g.*, see IPCC (2007b), and review of the criticism and corrective actions being undertaken, indicates that it seems unlikely there will be a significant impact on the current state of climate science; *e.g.*, refer to CSIRO and BoM (2010).

In conclusion, the AR4 remains as probably the most important summary of climate science today. If any serious scientific errors are identified these can be expected to be highlighted in the publication of AR5. The Working Group I report for AR5, (the IPCC's next major scientific report), is scheduled for finalisation in September 2013.

3. Greenhouse Gas Response

3.1. Overview

This section provides information on the Australian and Victorian Government's responses to the need for GHG emissions management. DGPL's and HRL's responses to GHG emissions management is placed in the context of international and national frameworks. Additionally, measures being implemented by HRL and DGPL to reduce GHGs from existing operations are set out in this section.

3.2. International and National Response

3.2.1. Overview

The international and national response to climate change has involved the development of an international treaty designed to limit the emissions of GHG and ozone depleting substances: the *Kyoto Protocol to the Framework Convention on Climate*.

3.2.2. The Kyoto Protocol

The objective of the Kyoto Protocol is to reduce the GHG emissions worldwide. The Kyoto Protocol establishes provisions to limit emissions of specified GHGs. Signatories to the *Kyoto Protocol* would be required to reduce GHG emissions by at least 5% below 1990 levels by 2008-2012.

On 3 December 2007, the former Australian Prime Minister, Kevin Rudd, signed the instrument of ratification of the Kyoto Protocol. As such, Australia has committed to meeting its Kyoto Protocol long term target, and has set a target to reduce GHG emissions by 60% on 2000 levels by 2050.

Additionally as a medium target the Government has committed to reduce Australia's carbon pollution to 25% below 2000 levels by 2020 if the world agrees to an ambitious global deal to stabilise levels of GHGs in the atmosphere at 450 parts per million CO_2 equivalent or lower. This will maximise Australia's contribution to an ambitious outcome in international negotiations. If the world is unable to reach agreement on a 450 parts per million target Australia will still reduce its emissions by between 5 and 15 per cent below 2000 levels.

3.2.3. Carbon Pollution Reduction Scheme (CPRS)

The main driver of the Government's plan to reduce Australia's GHG emissions is the Carbon Pollution Reduction Scheme (CPRS) which puts a limit on Australia's carbon pollution and makes polluters pay. It will use a 'cap and trade' emissions trading mechanism to limit carbon pollution. In a cap and trade scheme, the level of the scheme cap determines the environmental contribution of the Scheme: the lower the cap, the more abatement (reduction in emissions) required.

The number of tradable Australian emissions units will be equal to the scheme cap – if the cap were to limit emissions to 100 million tonnes of carbon dioxide equivalent (CO_2-e) in a particular year, 100 million emissions units would be issued for that year. Australian emissions units will be tradable and the price of units determined by the market. Businesses responsible for emissions sources covered by the CPRS will need to surrender an emissions unit for each tonne of CO_2-e that they have emitted during the compliance period.

To share the cost of making emissions reductions across the economy and to ensure that the CPRS meets its environmental objectives, the CPRS will cover a wide range of Australia's emissions.

In order to ensure robust energy and GHG emissions data is provided to the CPRS The *National Greenhouse and Energy Reporting Act 2007* (the Act) was passed on 29 September 2007, establishing a mandatory reporting system for corporate GHG emissions and energy production and consumption in Australia. The first reporting period under the Act commenced on 1 July 2008.

It is noted that on 27 April 2010 the former Prime Minister (Kevin Rudd) announced that the Government will not introduce the CPRS until after the end of the current commitment period of the Kyoto Protocol, (which ends in 2012), and only when there is greater clarity on the actions of other major economies including the US, China and India.

3.2.4. National Greenhouse Gas Inventory

The Department of Climate Change and Energy Efficiency (DCCEE) *National Greenhouse Gas Inventory 2007* (DCCEE, 2009a) has the dual purpose of providing estimates of Australia's net GHG emissions and of tracking Australia's progress towards its internationally-agreed target of limiting emissions to 108% of 1990 levels over the period 2008–2012. Australia has updated and published annual national GHG inventories for each year from 1990 to 2007 inclusive. The inventories are prepared according to international guidelines established by the IPCC and Kyoto accounting provisions.

In 2007, Australia's net GHG emissions using the Kyoto accounting provisions were 541.2 Mt of CO_2-e. The energy sector was the largest source of GHG emissions, accounting for 75.4% (408.2 Mt CO_2-e) of emissions in 2007, followed by agriculture (16.3%). For a breakdown of the GHG emission by sector and sub-sector, refer to **Table 3-1** below.

Table 3-1 Australian Net Greenhouse Gas Emissions for 2007

Sector and Sub-sector	Emissions (Mt)				
	CO_2	CH_4	N_2O	HCFCs/ PFCs SF_6	CO_2-e
All energy (combustion + fugitive)	372.1	33.3	2.7	NA	408.2
Stationary energy	289.5	1.3	1.0	NA	291.7

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Sector and Sub-sector	Emissions (Mt)				
	CO_2	CH_4	N_2O	HCFCs/ PFCs SF_6	CO_2-e
Transport	76.5	0.6	1.7	NA	78.8
Fugitive emissions from fuel	6.2	31.5	0.0	NA	37.7
Industrial processes	24.1	0.1	0.0	6.1	30.3
Agriculture	NA	67.9	20.2	NA	88.1
Waste	0.0	13.9	0.6	NA	14.6
Total Net Emissions	396.3	115.3	23.5	NA	541.2

Notes:
NA = not applicable
Source: National Greenhouse Gas Inventory 2007 (DCCEE, 2009a)

3.2.5. The Gillard Labor Government – A Cleaner Future for Power Stations

It is noted that the Federal Government's White Paper on the Carbon Pollution Reduction Scheme, (CoA, 2008), proposed to provide transitional assistance to generators that are producing above 0.86 t CO_2-e / MWh generated. In July 2010 the Gillard Labor Government announced its climate change policy leading up to the 21 August 2010 Federal Government election. The ALP (2010) statement, 'A Cleaner Future for Power Stations', indicates that a re-elected Gillard Labour Government will introduce tough new emissions standards for all new coal-fired power stations. A new emissions standard would be set with reference to the best practice coal-fired electricity generation technology, determined in consultation with stakeholders. "Our starting point will be below the level at which assistance was proposed by Federal Labor under the Carbon Pollution Reduction Scheme (CPRS)."

Note the performance figure provided in ALP (2010) is assumed to be at or close to 0.86 tonnes CO_2-e / MWh. The DGDPS GGI is below the figure of 0.86 t CO_2-e / MWh (as will be shown later in this report).

Furthermore the DGDPS complies with the ALP (2010) statement that "all new coal-fired power stations will be required to meet best practice emissions standard and be Carbon Capture and Storage-ready (CCS-ready)". The DGDPS has been designed to enable the potential retrofit of CO_2 capture technology when commercially viable.

3.2.6. Federal Government Election 2010

As at the date of this submission it is unclear who the new Federal Government will be and what will be the new Federal Government policies regarding climate change.

3.2.7. Australian Government Programs Relevant to the DGDP

There are several Australian Government programs, delivered by the Department of Resources, Energy and Tourism (DRET) that focus on energy use management and the driving of large-scale uptake of clean energy technologies. The two relevant programs providing support to DGDP are: (1) Low Emissions Technology Demonstration Fund (LETDF); and (2) Clean Energy Initiative (CEI). A summary of the programs and projects DRET web site[2], and relevant to the DGDP, is provided in the following paragraphs.

The objective of the Low Emissions Technology Demonstration Fund, (funding rounds ceased in March 2006), included demonstrating the commercial potential of new energy technologies for the delivery of long-term (large-scale) greenhouse gas emission reductions in Australia. One of the five projects being funded by the Fund is the DGDP. The Fund recognised HRL's IDGCC technology as being suitable for carbon capture with prospects for CO_2 removal prior to combustion. The Australian Government committed $100 million to the DGDP.

The Clean Energy Initiative (CEI, $5.1 billion) includes three sub-programs and of these the Carbon Capture and Storage (CCS) Flagships Program ($ 2.4 billion)[3] to accelerate the commercial deployment of carbon capture and storage (CCS) projects.

Of the four projects shortlisted under the CCS Flagships Program, (announced on 8 December 2009), the CarbonNet proposal is an integrated multi-user capture, transport and storage infrastructure project for electricity generation sources of CO_2 in the Latrobe Valley. HRL forms part of the CarbonNet proposal. At the same time $120 million of funding was announced for pre-feasibility studies for the (four) short-listed projects. In addition, the Education Investment Fund (EIF) ($200 million) supports the CCS research infrastructure component for the four projects requiring partnering with research institutions such as universities.

3.3. State of Victoria Response

3.3.1. Overview

The resource life of the Victoria brown coal resource as accessible Economic Demonstrated Resources (EDR) is estimated to be 490 years; all Australian EDR for brown coal is in Victoria with 93% of EDR located in the Latrobe Valley; Geosciences Australia (2008). This enormous

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[2] DRET 'Energy' web page; http://www.ret.gov.au/energy/Pages/index.aspx, accessed 4 June 2010.

[3] The Global CCS Institute (annual funding of $100 million by the Australian Government) was announced by the Australian Government in September 2008. The Institute has received international support from more than 20 governments and more than 80 non-government bodies.

resource comes at a cost: about half of Victoria's greenhouse gas emissions are due to the combustion of brown coal.

The 2002 Victorian Greenhouse Strategy commenced a 3-year program of actions to reduce greenhouse emissions across a range of industry sectors and the Greenhouse Challenge for Energy Position Paper outlined the Government's policy to reduce greenhouse gas emissions from the stationary energy sector. The 2005 Victorian Greenhouse Strategy Action Plan Update accounted for national and international developments in climate change policy[4].

In 2006 the Victorian Government set a long-term target of reducing 2000 levels of GHG emissions by 60%, by 2050 (Victorian Government, 2009), reflecting Australia's commitment to meeting its Kyoto Protocol target.

Other recent Victorian Government responses to climate change include the '*Our Environment, Our Future – Sustainability Action Statement*' (funding over $200 million). Also, the Renewable Energy Action Plan was developed to accelerate the development of renewable energy through a range of measures including the Victorian Renewable Energy Target (VRET). Similarly, the Energy Efficiency Action Plan sought to identify economy-wide improvements in energy efficiency to reduce greenhouse gas emissions and enhance energy supply security while reducing energy bills for households and businesses.

The Victorian Government also recently released the *Future Energy Statement* (June 2010), which will guide the transformation of the State's energy sector. The *Future Energy Statement* recognises expected growth in low emissions forms of fossil fuel energy, the role carbon capture and storage can play in further reducing greenhouse gas emissions and sets out how the Victorian Government will play a role in securing a sustainable energy future.

3.3.2. Victorian Government Climate Change White Paper – The Action Plan

In July 2010 the Victorian Government released its *Climate Change White Paper – The Action Plan*[5] (VG, 2010), which states that 'The Victorian Government commits to no new approvals being granted for new coal fired power stations based on conventional brown coal technologies'.

The Dual Gas Demonstration Power Station meets this criterion.

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[4] Victorian Government website, http://www.climatechange.vic.gov.au/, accessed 4/6/10.

[5] Victorian Government website, http://www.premier.vic.gov.au/climate-change, accessed 6/8/10.

Furthermore, VG (2010) indicates the Victorian Government will set a target emissions level of '0.8 tonnes of CO_2 equivalent (per MWh)' for new power stations. This is consistent with the Federal Government's average GGI estimate of 0.86 tonnes CO_2-e/MWh ('as generated') for fossil fuel power generation in Australia (see CoA, 2008; ALP, 2010).

The DGDPS will meet the VG (2010) target emissions level of 0.8 t CO_2-e / MWh, (as will be shown later in this report).

3.3.3. Victorian Government Technology Programs Relevant to the DGDP

This section describes Victorian Government technology programs to cut GHG emissions. Of prime relevance to DGDP is the Victorian Government's Energy Technology Innovation Strategy (ETIS). The purpose of the ETIS is to support advances in low emission technologies, with $180 million funding for research, development, demonstration and deployment for pre-commercial energy technologies. A focus of ETIS is on clean coal technologies and $80 million of funding available over a 5-year period is to support new pre-commercial demonstration plants, making use of clean coal technologies on an industrial scale. This includes a $50 million grant to support the building and operating of the DGDP (DPI, 2008). This is in addition to the Australian Government commitment of $100 million as part of the LETDF (see **Section 0**).

As part of CarbonNet, on 20th January 2010 the Victorian Government announced funding of up to $29 million for pre-feasibility studies to be shared among five projects, the first to receive ETIS funding for new large-scale, pre-commercial CCS demonstration projects in Victoria (Minister for Energy and Resources, 2010). The funding includes up to $3.5 million to investigate the feasibility of a gasification, pre-combustion CO_2 capture project being developed by HRL. Remaining funding of $110 million will be allocated to projects that successfully meet expectations (Minister for Energy and Resources, *ibid.*).

In **Section 0**, a multi-user CO_2 capture, transport and storage infrastructure proposal for the Latrobe Valley, (CarbonNet), was mentioned as one of four projects shortlisted under the Australian Government's CCS Flagships Program. CarbonNet involves the development of a series of pipelines from high CO_2 emitters in the Latrobe Valley to geological carbon storage sites in proven offshore and onshore areas in Victoria (*e.g.*, Minister for Energy and Resources, 2009). The Minister for Energy and Resources *(ibid.*) stated that the proposal would see Victoria become the location for one of the 20 large-scale carbon capture, transport and storage projects required worldwide, outlined by the G8 as being essential to reduce future global CO_2 emissions.

3.3.4. EPA Victoria Programs and Guidelines

As part of Victoria's greenhouse strategy, the Environment Protection Authority Victoria (EPA) initiated the Industry Greenhouse Program. Commencing in 2002, this program aims to improve the energy efficiency of Victoria industry and reduce the associated GHG emissions. It also aims to improve the management of GHGs that are not associated with energy usage.

The Industry Greenhouse Program's statutory requirements are enacted through the *State Environment Protection Policy (Air Quality Management)* (SEPP). One of the aims of SEPP is to support Victorian and national measures to address the enhanced greenhouse effect and depletion of the ozone layer. The requirements for management of GHGs are set out in clause 33 of SEPP.

Guidance on implementation of the statutory requirements for the Industry Greenhouse Program is contained in the *Protocol for Environmental Management – Greenhouse Gas Emissions and Energy Efficiency in Industry* (PEM).

The assessment steps to demonstrate compliance with the SEPP (2001) and relevant to the Works Approval Assessment are set out as follows:

- Step 1: Estimate energy consumption: Estimate the annual energy consumption associated with the proposed works and calculate the associated GHG emissions (as CO_2 equivalents) in accordance with conversion factors published by the Department of Climate Change.
- Step 2: Estimate direct greenhouse emissions: If the proposed works will result in non-energy related GHG emissions, estimates of the quantity of GHG emissions should be provided (as CO_2 equivalents).
- Step 3: Discuss best practice for energy use and GHG emissions: Where the anticipated level of energy use associated with the application is 500 gigajoules per annum or more (or greater than 100 tonnes of energy related $CO_{2\text{-}e}$ emissions per annum), applicants must identify and implement best practice with respect to the activities that are the subject of the application.

The assessment of GHG emissions associated with the proposed DGPS to follow in later sections of this report, follow the three-step process set out above.

The Environment Resource Efficiency Plan (EREP) is an innovative regulatory program to help Victorian businesses meet climate change and resource scarcity challenges. EREP aims to build on the Industry Greenhouse Program (IGP).

The EREP requires the largest commercial users of energy and water to identify and implement actions that reduce energy and water use and minimise waste. The statutory requirements for the EREP program are set out in the *Environment Protection Act* 1970 and the *Environment Protection (Environment and Resource Efficiency Plans) Regulations* 2007.

Commercial and industrial sites in Victoria that use more than 100 TJ of energy and / or 120 ML of water per year need to participate in the EREP program. Participating businesses need to register with EPA, prepare and implement a plan that identifies actions to reduce energy and water use, and waste generation.

Sites that are subject to works approval can apply for an exemption from the requirement to prepare an EREP for up to five years from when the exemption is granted. This exemption is designed to support businesses that investigate resource efficiency opportunities in designing their sites.

3.4. Other DGPL Greenhouse Gas Management Initiatives

3.4.1. Overview

This section sets out DGPL's GHG emissions management initiatives primarily through the research activities of parent company HRL Limited. These initiatives are additional to the involvement in Australian and Victorian Government technology programs described in the preceding sections.

3.4.2. Development of Coal Gasification for Power Generation by HRL

Brown coal is abundant in Victoria and the cheapest source of fossil fuel for power generation in Australia, but leads to higher emissions of GHGs when used in conventional power stations, in comparison with other fuels.

The Integrated Drying and Gasification Combined Cycle (IDGCC) process enables higher efficiency when used with Combined Cycle Gas Turbine power generation. Further, pre-combustion CO_2 capture is well suited to IDGCC due to the concentrated CO_2 gas stream.

From 1989 to the present HRL has developed and operated a 0.5MW Coal Gasification Demonstration Unit (CGDU) at Mulgrave, Victoria. Initially the CGDU demonstrated the gasification of a range of coals. In more recent times it has been operated to supply a syngas stream for pre-combustion carbon capture trials. These trials are aimed at reducing the technical risk and cost of pre-combustion capture for Victorian coal-fired stations with new coal burning technologies employing gasification (CO2CRC, *ibid.*). The trials will evaluate pre-combustion CO_2 capture technologies to identify the most cost-effective for application to coal gasification power-generation technology. The carbon capture trials will include detailed performance evaluations of the following carbon capture technologies: (1) Solvent absorption; (2) Membrane separation; and (3) Pressure swing adsorption; refer to CO2CRC (2010) for more details.

A 10MW Coal Gasification Development Facility (CGDF) was developed and operated near Morwell in the 1990s in Latrobe Valley. The CGDF successfully demonstrated the IDGCC process from coal preparation through to syngas combustion in a grid-connected 5MW gas turbine and Heat Recovery Steam Generator (HRL, 2005).

On 24th September 2009, HRL announced the establishment of special-purpose company DGPL to develop a commercial-scale demonstration IDGCC project. More details are provided in the next section.

3.4.3. DGPL's Commercial Scale Demonstration IDGCC Project

The key advantages of the DGDPS, not only for DGPL but for all Victorians, is its lower GHG intensity in comparison with conventional coal fired power stations and its technology pathway towards lower greenhouse intensity and carbon capture (see **Section 7.3.1**). Also, the Combined Cycle Gas Turbine (CCGT) uses gas turbine waste heat to improve the power generation efficiency of the overall plant as opposed to open cycle gas turbine plant.

As will be seen in later sections of this assessment, the GHG emissions performance of the DGDPS is expected to be better than existing brown coal power stations in the Latrobe Valley, and better than brown coal supercritical.

Another key advantage of IDGCC technology is the expected development pathway towards even lower GHG emissions intensity power generation from brown coal when combined with pre-combustion CO_2 Capture and Storage (CCS). IDGCC technology combined with pre-combustion CCS is expected to result in a CO_2 emissions intensity of approximately 0.26 t CO_2-e / MWh (DGPL estimate), which is lower than that of the current NG-fuelled combined cycle power generation new plant standard of 0.35 t CO_2-e / MW (AGO, 2006). The DGDPS has been designed to enable the potential retrofit of CO_2 capture technology when commercially viable.

3.4.4. HRL Involvement in *Greenhouse Challenge Plus* (1995–2009)

Greenhouse Challenge Plus was a volunteer program that required business to report on energy usage and CO_2 emissions and to identify ways to reduce energy consumption and emissions. DEWHA states that more than 700 organisations covering key areas of Australian industry participated in Greenhouse Challenge Plus (DEWHA, 2009)[6]. Investments in new technologies, improvements in the efficiency of processes and energy use, fuel switching and capturing fugitive emissions all contributed to reducing GHG emissions (DEWHA, *ibid.*).

Through its subsidiary Energy Brix Australia Corporation (EBAC), HRL owns and operates the 170 MW Energy Brix Power Station on the EBAC site at Morwell. EBAC is a licensed power

[6] DEWHA, http://www.environment.gov.au/archive/settlements/challenge/index.html, accessed 6/12/09.

generator operating in the wholesale National Electricity Market. Also, through its subsidiary Industrial Energy, HRL markets briquettes manufactured in a co-generation plant associated with the power station.

EBAC was an active participant in the Greenhouse Challenge Plus program of the Department of Environment and Heritage / Australian Greenhouse Office, since its inception in 1995. Abatement actions undertaken by EBAC are estimated to have reduced the annual greenhouse emissions by approximately 2,500 t CO_2-e in 2001 progressively through to 47,200 t CO_2-e in 2007 (EBAC, 2008).

Recent main abatement actions were the installation of mill classifier upgrade and online cleaning of water blowers and soot-blowers in Boiler 7–expected to have reduced GHG emissions by more than 4,800 t CO_2-e per annum from 2008 onwards.

A program of re-lamping, maintenance and replacement of existing luminaries started in 2005 was 25% complete by the end of 2007 leading to a GHG emissions reduction of 355 t CO_2 per annum.

More recently HRL has been registered under the National Greenhouse Energy Reporting System (NGERS) and has submitted its report for the Financial Year 2008/09.

3.4.5. HRL Involvement in Generator Efficiency Standards

The objective of the Generator Efficiency Standards (GES) measure is to encourage best practice in the efficiency of fossil-fuelled electricity generation and to reduce the GHG intensity of energy supply.

The GES measure applies to all fossil-fuelled power generation plants with an electrical capacity of 30MW or more and with an annual electrical output of 50GWh per year. The Australian Government enters into legally binding Deeds of Agreement with businesses affected by the GES through the Greenhouse Challenge Plus program.

HRL through EBAC, participated in GES (as well as the Greenhouse Challenge program), and has assessed its operations and compared these with best practice as set out in the GES Technical Guidelines.

4. Brief Description of Proposal

The primary purpose of the proposed DGDPS is to use a gaseous fuel synthesised from brown coal, (syngas), to generate electricity with a significantly lowered GHG signature relative to conventional brown coal-fired power stations.

The proposed 600 MW DGDPS will demonstrate IDGCC technology at commercial scale, to be located within the Energy Brix Australia Complex Corporation (EBAC) site in the Latrobe Valley. The DGDPS comprises two Integrated Drying and Gasification units feeding syngas to two Combined Cycle Gas Turbines (CCGTs). The Combined Cycle element of the facility uses Heat Recovery Steam Generators to improve the efficiency of the gas turbine power generation process. A flare may also be used (on very rare occasions), for the management of excess gas flow.

The DGDPS is planned to operate on a mix of syngas and NG, or NG only. The fuel mix over the operating life of the DGDPS is expected to be determined primarily by NG prices, electricity prices, availability, cost and quality of coal supplies, contractual arrangements for gas supply, the reliability of the gasification process, and the price of GHG emissions permits. These parameters are expected to fluctuate by the hour (HRLT, 2009). The initial construction phase of the DGDP is planned for 2011 to 2013, including installation of the first gasifier and two CCGTs for power generation. In this first stage approximately half of the power generation capacity will be by syngas and the remainder by NG. The second gasifier is planned to be installed after acceptable performance is demonstrated for the first. However, DGPL may operate a single gasifier with the balance of fuel needs met by NG. Also, if IDGCC non-success occurs, the DGDP can be operated as a NG (only)-fuelled CCGT power plant. With the two gasifiers of a successful IDGCC scenario in place, the gas turbines are planned to operate on syngas approximately 85% of the time and on NG up to 10% of the time (with 5% down-time).

Four case studies studied for this assessment, covering the expected range of emissions for DGDPS, are set out in **Table 4-1**. Cases 1–3 are IDGCC technology success scenarios and Case 4 is an IDGCC technology non-success scenario. The average fuel use amounts listed in **Table 4-1** were calculated from annual variations in fuel amounts provided by DGPL for the DGDP's projected 30-year life; the full details are provided in **Appendix A**.

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Table 4-1 Fuel Usage Details for Four DGDPS Case Studies

DGDPS Operating Scenario	Coal Source and Syngas Usage	Natural Gas Usage
Case 1	Two gasifiers fuelled by: • MOC syngas from 2012/13–2015/16 • YNX syngas from 2016/17 to 2026/27 • MOC syngas from 2027/28–2041/42	A large amount of NG used throughout lifetime.
	Average coal usage: 2,345 kT p.a.	Average 11,425 TJ p.a.
Case 2	Two gasifiers fuelled by: • MOC syngas from 2012/13–2015/16 • YNX syngas from 2016/17 to 2026/27 • MOC syngas from 2027/28–2041/42	A moderate amount of NG throughout lifetime.
	Average coal usage 2,636 kT p.a.	Average 8,715 TJ p.a.
Case 3	Two gasifiers fuelled by MOC syngas over 30-year lifetime	A moderate amount of NG throughout lifetime.
	Average coal usage 2,803 kT p.a.	Average 9,518 TJ p.a.
Case 4	MOC syngas-fuelled by single gasifier ceasing after 4 years in 2015/16	DGDPS fuelled by NG only from 2016/17–2041/42.
	MOC coal usage average 322 kT p.a. (average of first 4 years only)	Average 14,108 TJ p.a.

5. Assessment Methodology

5.1. Overview

An assessment of both direct and indirect greenhouse gas emissions is presented in this Section for the proposed DGDP. Fuel combustion associated with an electricity generation process is the only source of direct emissions. Emissions associated with fuel production (manufacture), extraction and transportation are categorised as indirect.

In summary, the following activities are expected to be the major sources of GHG emissions, direct and indirect, associated with the proposed DGDP:

- Brown coal and NG extraction;
- Transportation of brown coal and NG to the DGDPS site; and
- At the DGDPS site:
    - Production of synthesis gas (syngas); and
    - Combustion of syngas and NG.

The DGDPS will not use diesel as a supplementary or emergency fuel.

The following sub-sections describe the derivation of direct and indirect GHG emissions estimates associated with the proposed DGDPS.

5.2. National NGERS and Victorian EPA (PEM) Methods

5.2.1. Overview

The GHG emissions estimates for the proposed DGDPS were undertaken in accordance with the most current techniques as set out in the Department of Climate Change and Energy Efficiency (DCCEE) technical manual, *National Greenhouse and Energy Reporting System Measurement, Technical Guidelines for the estimation of greenhouse gas emissions by facilities in Australia* (DCCEE, 2009b). This document includes the latest methods for estimating emissions based on the Commonwealth of Australia legal documents: *National Greenhouse and Energy Reporting (Measurement) Determination 2008 as amended by the National Greenhouse and Energy Reporting (Measurement) Amendment Determination 2009 (No. 1).*

The use of the current GHG emissions estimation techniques for the DGDPS proposal, as set out in DCCEE (2009b), is in accordance with the EPA Victoria requirements and guidance; *i.e.*, EPA (2002) and EPA (2006). Recently a new 2010 version of the Technical Guidelines was released by the Department (DCCEE, 2010). A comparison of the techniques set out in the 2010 and 2009 Technical Guidelines found no changes to emissions factors or methods that would affect this assessment for DGDP.

5.2.2. Definitions for Emissions Scope

DCCEE (2009c) describes the three types of assessment categories:

- Scope 1 emissions: Direct (or point-source) emissions at the point of emission release; *e.g.*, due to fuel use, energy use, manufacturing process activity, mining activity, and on-site waste disposal.
  - For DGDP, the Scope 1 emissions are the CO_2-e emissions from the combustion of syngas, NG and char, with points of release being the facility's air emission stacks.
- Scope 2 emissions: Indirect emissions due to the generation of the electricity purchased and consumed by an organisation. The GHG emissions occur from fuel combustion at the supplying power station.
  - The DGDP, (generating its own electricity), will make very minimal electricity purchases which are considered to be covered in this assessment by the conservative (high) estimates for annual Scope 3 emissions, therefore there are no Scope 2 emissions.
- Scope 3 emissions: Indirect emissions due to production and transport of fossil fuels or the consumption of purchased electricity. Scope 3 emissions can include (but not limited to): (1) Extraction, production and transport of purchased fuels consumed; (2) Extraction, production and transport of other purchased materials or goods; (3) Employees commuting to and from work; (4) Transport and disposal (off-site) of waste.
- For DGDP, the major Scope 3 emissions are the indirect CO_2-e emissions attributable to the extraction, production and transport of:
  - Brown coal and NG for consumption by DGDP; and
  - Materials used in construction of DGDP, especially steel and concrete.

5.2.3. NGERS Emissions Estimation Techniques

DCCEE (2009b) sets out Method 1 techniques for basic GHG emissions estimates using specified (regional) emission factors. Method 1 is useful for estimating emissions from relatively homogenous sources, such as from the combustion of standard liquid and gaseous fossil fuels.

The primary activity of the DGDPS facility is electricity generation. As such, in accordance with DCCEE (2009b), the more accurate Method 2 procedures have been used; descriptions of the key procedures are set out in the following points:

- Facility-specific method using industry sampling and Australian or international standards listed in the Determination or equivalent for analysis of fuels and raw materials to provide more accurate estimates of emissions at facility level.

- Enables corporations to undertake additional measurements; *e.g.*, the qualities of fuels consumed at a particular facility, in order to gain more accurate estimates for emissions for that particular facility.
- Draws on the large body of Australian and international documentary standards prepared by standards organisations to provide the benchmarks for procedures for the analysis of, typically, the critical chemical properties of the fuels being combusted.
- Likely to be most useful for fuels that exhibit some variability in key qualities such as carbon content, from source to source. This is the case for coal in Australia.
- Based on existing technical guidelines used by reporters under the Generator Efficiency Standards program. The possibility to report using this 'higher order' (more accurate) approach is extended by the Determination from the electricity industry to all major consumers of fossil fuels.

A commonly used GHG emissions benchmark for a power station for ease of comparison with other power generators is a mass emission of CO_2-e per net energy sent out (Net Actual Generation[7]); *e.g.*, provided in units of tonnes CO_2-e per MegaWatt hour (t CO_2-e / MWh SO).

The more accurate techniques (Method 2) have been used for DGDPS and these are described in the following sections.

5.3. GHG Emissions Estimates – Detailed Methodology

5.3.1. Input Data Provided by HRL Technology

Detailed descriptions for four DGDPS lifetime operating scenarios provided by HRL Technology, covering a wide range of potential syngas-and-natural gas fuel mix scenarios for the DGDP's expected 30-year lifetime, provided the basis of this assessment. The key input data are annual brown coal quantities and NG quantities to be used by the syngas plant for the scenarios studied, and data to be used for estimates of Scope 3 emissions. Scope 2 emissions are zero as there will be no significant electricity purchases by the demonstration power station.

In the proposed DGDPS operation, coal will be consumed via the gasification path or in char burners, and DGDPS process modelling for input to HRLT (*ibid.*) was based on 89% of the carbon in the coal being gasified and combusted, the remaining 11% combusted in the char burners. At least some NG will be used by the plant always.

[7] NAG: the actual electrical MWh generated by the unit during the period being considered less any generation (MWh) utilised for that unit's station service or auxiliaries; *e.g.*, see SKM (2000).

In this assessment, all the carbon in the brown coal quantities used by the plant, whether by combustion of syngas or in char burners, has been assumed to form CO_2. However, although all the carbon in the brown coal has been assumed to form CO_2, (in the calculated estimates), the Method 2 emissions factor for CH_4 emissions from brown coal usage has been employed in the calculated GHG estimates.

5.3.2. NGERS Method 2 CO_2-e Emissions Estimates for Brown Coal Usage

The NGERS Method 2 emissions estimation technique for solid fuel with a default oxidation factor was used for this assessment, as set out in Division 2.3.1.1 of DCCEE (2009b). For CO_2 emissions, the relevant four equations may be simplified to the following single equation for a GHG mass emission, G_S (t CO_2):

$$G_S = a \times Q \times O_F \times C_{dry} \times (1 - M), \qquad (1)$$

where 'a' is a constant (3.664) converting a carbon mass to a CO_2 mass; Q is the annual mass quantity (tonnes) of brown coal used; O_F is the oxidation factor, C_{dry} is the carbon mass fraction of the dry coal, and M is the moisture mass fraction of the 'as received' fuel.

HRLT (2009) advised using a conservative value of 100% for O_F, (this assumes that all the carbon in the brown coal used by the plant is converted to CO_2).

A summary of the input data to be used with Equation (1) is provided in **Table 5-1** (HRLT, 2009).

- **Table 5-1 DGDPS Brown Coal Properties (HRLT, 2010b)**

Parameter	Morwell Coal (MOC)	Yallourn Coal (YNX)
Oxidation factor (O_F) (set to unity, conservative-high)	1.0	1.0
Carbon mass fraction of dry brown coal (C)	0.684	0.657
Moisture mass fraction of 'as received' (combusted) fuel (M)	0.610	0.523

* Note: In the table above, the use of unity for O_F leads to conservative (overestimated) results for calculated CO_2-e mass emissions, as advised by HRLT.

Equation (1) allows us to calculate CO_2 emissions from brown coal usage, but not CH_4 and N_2O, which requires an estimate for energy content of the coal. Higher Heating Values (HHVs) for the brown coal were calculated from data provided in HRLT (2010b). The CO_2 emission factors for brown coal then follow directly and a summary of results is provided in **Table 5-2**. Note also the drier Yallourn coal has a higher HHV.

- **Table 5-2 Calculated CO_2 Emission Factors for Brown Coal Usage by DGDPS**

Parameter	Morwell Coal (MOC)	Yallourn Coal (YNX)	Unit
Calculated Gross Wet Specific Energy (Higher Heating Value)	10.40	12.40	GJ / tonne
Calculated emission factor	0.9774	1.1483	kg CO_2 / kg fuel
Calculated emission factor	94.01	92.59	kg CO_2 / GJ

A CH_4 emission factor of 0.01 kg CO_2-e / GJ and a N_2O emission factor of 0.4 kg CO_2-e / GJ for brown coal usage were selected from Table 2.2.2, DCCEE (2009b), in accordance with Method 2 estimation procedures. Thus, the conservative (higher) estimates for total (CO_2-e) emission factors for brown coal usage by the proposed DGDPS are provided in **Table 5-3**.

- **Table 5-3 Total (CO_2–e) Emission Factors for Brown Coal Usage by DGDPS**

Brown Coal Usage Scenario	CO_2-e emission factor
Using syngas created from MOC	94.42 kg CO2-e / GJ
Using syngas created from YNX	93.00 kg CO2-e / GJ

5.3.3. NGERS Method 2 CO_2-e Emissions Estimates for Natural Gas Usage

The proposed DGDPS will always use at least some NG and also, the facility will have the capability to operate wholly on NG. The molecular composition of the NG fuel to be used by DGDPS is provided in **Table 5-4** (HRLT, 2010b).

- **Table 5-4 Molecular Composition of DGDPS's NG Fuel (HRLT)**

Species	Composition (% by mole)
Methane (CH_4)	90.03 %
Ethane	5.84 %
Propane	1.12%
Butane	0.2083%
Oxygen (O_2)	0.1%
Nitrogen (N_2)	0.7947%
Carbon dioxide (CO_2)	1.907%

The DCCEE (2009b) Method 2 techniques for emissions released from the combustion of gaseous fuels, (Part 2.3), have been used for estimates of CO_2-e emissions from the NG component of DGDPS's fuel consumption. The NG composition provided for DGDPS were used with the techniques set out in the international standard *ISO 6976* (1996)[8], (*Natural gas – Calculation of*

[8] International Standard, ISO 6976, Second edition,1995.

calorific values, density, relative density and Wobbe index from composition), to determine the NG properties listed in **Table 5-5**. The energy content of the fuel, (which is readily calculated), is also listed in the table.

Table 5-5 Calculated NG Properties for DGDPS

Property	Calculated value for DGDPS
Gross calorific value (or Higher Heating Value), volumetric basis, (water vapour in combustion products condensed to liquid)	39.205 MJ/m^3
Fuel density	0.75741 kg/m^3
Energy content	51.763 MJ / kg

Then, in accordance with DCCEE (2009b), the CO_2 mass emission factor for NG was calculated using the equations detailed in Section 2.22 of DCCEE (*ibid.*). The CH_4 emission factor was calculated from the IPCC (2006) guidelines corrected to gross calorific values (see Section 2.27 of DCCEE, *ibid.*). The N_2O emission factor is simply the Method 1 estimate (see Section 2.19 of DCCEE, *ibid.*). A summary of the calculated results is provided in **Table 5-6**. The Method 1 emission factors are listed also, for comparison.

Table 5-6 Calculated Emission Factors for NG Usage by DGDPS

Parameter	Method 2 Emission Factor kg CO_2–e / GJ	Method 1 Emission Factor kg CO_2–e / GJ
Emission factor, CO_2	50.928	51.2
Emission factor, CH_4	0.086452	0.1
Emission factor, N_2O	0.03	0.03
Total emission factor	51.045	51.33

With respect to the emission factor for N_2O, it is worthwhile noting that IPCC (2006) has used an inaccurate USEPA result for gas turbines; overestimated by an order of magnitude. The DCCEE (2009b) NGERS Method 1 value (0.03 kg CO_2-e / GJ) has not been affected by this inaccuracy. However the preceding Australian Greenhouse Office (AGO) workbook, AGO (2005), seems to have been affected with its larger total Scope 1 emission factor of 51.9 kg CO_2-e / GJ. The preceding AGO workbook again, for stationary sources, (AGO, 2004), provides the more accurate information for N_2O.

From the NGERS Method 2 data and results listed in **Table 5-5** and **Table 5-6**, the calculated annual CO_2-e emissions for an annual NG usage is straightforward; *i.e.*, simply,

$$G_{NG} \text{ (t CO}_2\text{-e per annum)} = Q \text{ (GJ per annum)} \times EF \text{ (t CO}_2 \text{ / GJ)}. \qquad (3)$$

6. Greenhouse Gas Emissions Estimates

6.1. Overview

This section provides the results for GHG emissions estimates for the four 30-year nominal operating scenarios investigated for the proposed DGDPS. Scope 1 and Scope 3 emissions estimates are provided in this section, with more detailed results provided in **Appendix B**. Scope 2 emissions are expected to be negligible as electricity consumed at the demonstration power station site will be generated on-site (HRLT, 2009).

This section studies electrical energy data 'as generated' for comparison with performance data from other power stations and technologies. In some instances this is estimated from publically available 'sent out' data.

6.2. Scope 1 GHG Emissions Estimates

The calculated project average Scope 1 greenhouse gas intensity (GGI) and annual average GHG emissions for the proposed DGDPS are provided in **Table 6-1**. The 'project average' GGIs have been calculated for the DGDPS's projected 30-year lifetime; *i.e.*, by dividing the lifetime GHG emissions by the lifetime electrical energy generated.

- **Table 6-1 Calculated Scope 1 Annual Average GHG Mass Emissions for DGDPS**

DGDPS Operating Scenario	Project Average Greenhouse Intensity (t CO_2-e / MWh)	Project Annual Average Emissions (kt CO_2-e per annum)
Case 1	0.73	3,024
Case 2	0.77	3,201
Case 3	0.78	3,238
Case 4	0.45	762

The theoretical maximum greenhouse gas emission for the proposed DGDPS is estimated to be 4.2 Mt CO_2-e per annum. This is based on the maximum output from the power plant, with the gas turbines fired 85% of the time on syngas and 10% of the time on natural gas. (It is assumed that the gas turbines are not available for 5% of the time due to planned and unplanned outages). The theoretical maximum also includes maximum supplementary duct firing with natural gas (for the steam turbine) for 95% of the time.

However this theoretical emissions maximum is very unlikely to occur and as such has not been studied in detail in this assessment. Instead, three IDGCC success scenarios have been studied, with estimated average emissions of approximately 3.0 to 3.2 Mt CO_2-e per annum over the DGDPS's projected 30-year life as shown in **Table 6-1**.

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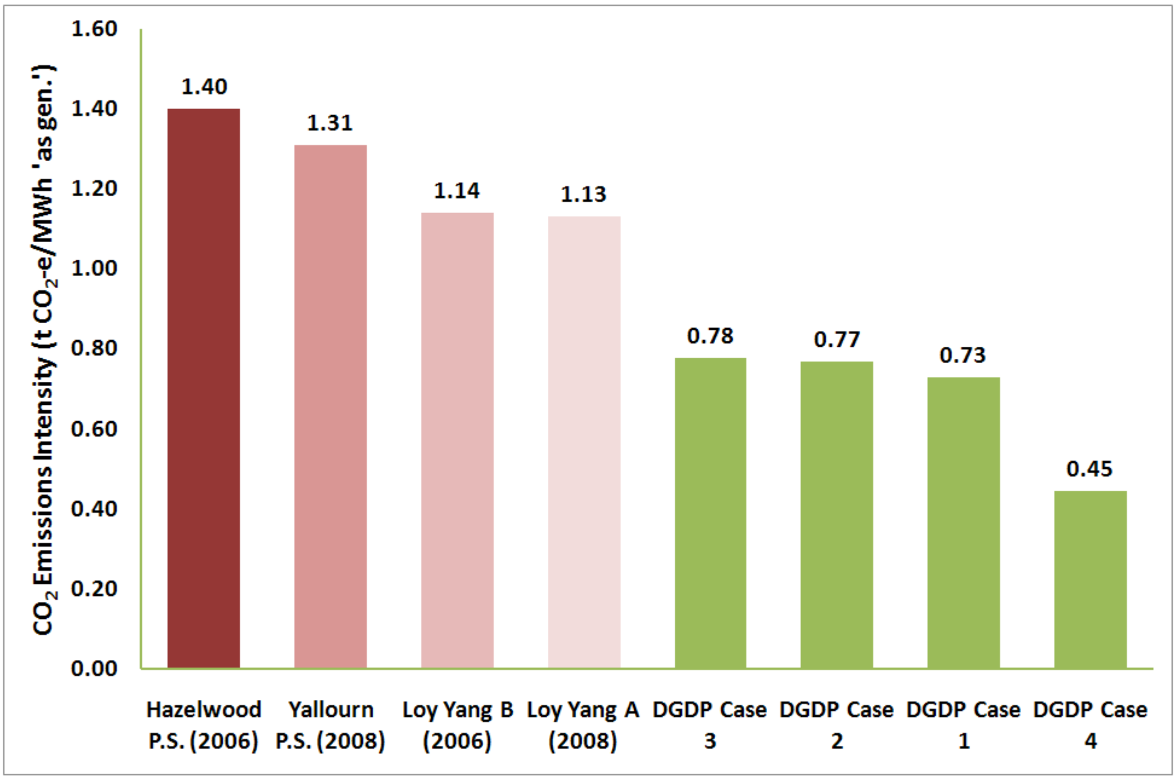
6.3. Benchmarking of DGDPS Scope 1 Emissions

6.3.1. Comparison with Existing Brown Coal Power Generators

The calculated Scope 1 GHG emissions intensities for DGDPS (Cases 1 to 4) are compared with GGIs from other (existing) Latrobe Valley brown coal power generation facilities in **Figure 6-1** Sources for these other GGI data are: International Power Hazelwood, *Social and Environment Report 2006*; TRUenergy, *Social and Environmental Snapshot* (2009); International Power Australia, *Loy Yang B Power Station Environmental Performance Report 2006*; Loy Yang Power, *Sustainability Report 2008* (see also **Appendix C**). It has been assumed that Hazelwood and Yallourn Power Stations consume approximately 8% of energy internally and that Loy Yang A and B consume approximately 7% of energy internally.

- **Figure 6-1 GGI: DGDPS Cases vs. Existing Latrobe Valley Power Stations**



DGDPS is a highly flexible plant with operation of the gas turbines possible on either natural gas or syngas (or with a mixture of the two). Supplementary duct firing on natural gas in the HRSG allows additional power generation when required.

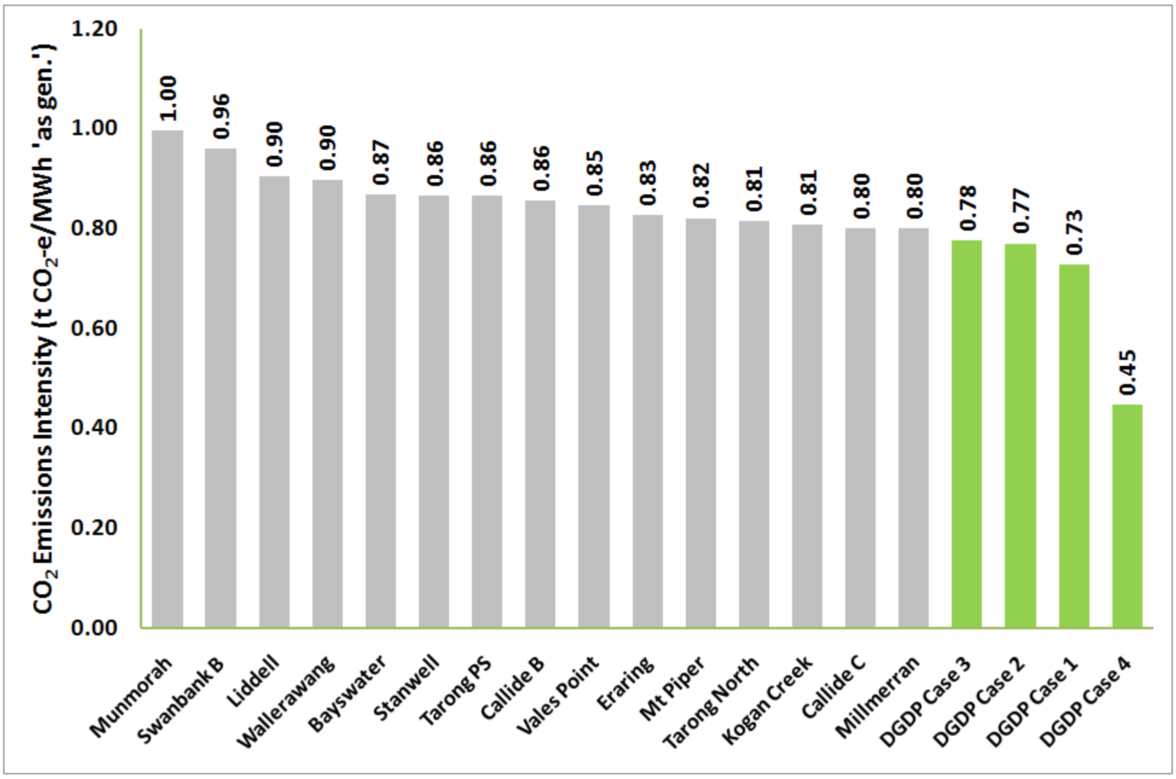
The actual mode of operation, (and therefore the greenhouse intensity of the plant), will depend upon the power price, fuel price, fuel source and permit price under a future emissions trading scheme. It is likely that the mode of operation will also change over the life of the plant as a result of commercial and regulatory changes.

The successful proving of the gasification technology will allow brown coal fired base-load power generation with a substantially lower greenhouse intensity than the current brown coal-fired power stations in Victoria. The project average GGI is expected to be in the range of 0.73 to 0.78 t CO_2-e / MWh over the life of the project, depending on the quantity of natural gas consumed. This is approximately 31% to 36% lower than the current best performing Latrobe Valley brown coal power station; *i.e.*, Loy Yang A with GGI of approximately 1.13 tonnes CO_2-e / MWh. This is approximately 45% to 48% lower than the Hazelwood Power Station which has a GGI of approximately 1.40 tonnes CO_2-e / MWh.

6.3.2. Comparison with Existing Black Coal Power Generators

The predicted project average GGIs for the four modelled DGDPS cases are compared with existing black coal-fired power plants in **Figure 6-2**. It has been assumed that existing black coal power stations consume approximately 6% of energy internally.

- **Figure 6-2 GGI: DGDPS Cases vs. Existing Black Coal Fired Power Stations**



Inspection of **Figure 6-2** shows that the four DGDPS Cases have GGIs lower than all the black coal power plants (refer to **Appendix C** for data sources). Note that DGDPS Case 4 is the IDGCC non-success case that reverts to NG and so has the lowest GGI of this sample.

6.3.3. Comparison with Best Practice Technologies

Currently there are no pulverised fuel (pf)-fired supercritical power stations operating on brown coal in Australia. However, best practice or new plant standards were issued by AGO (2006) for a set of steam conditions and assuming wet cooling; refer to **Table 6-2**. A black coal supercritical example is also provided in the table.

The GGIs for the DGDPS cases (0.73–0.78 t CO_2-e/MWh) are significantly better (less) than the brown coal supercritical examples and lower or on par with black coal supercritical. AGO (2006) provides GGIs ranging from 0.72 to 0.85 t CO_2/MWh for black coal pf-fired supercritical plant for varying ambient conditions, fuel properties and wet / dry cooling. The GGI of 0.78 t CO_2/MWh, (the example listed in **Table 6-2**), is for a 90.1 kg CO_2/GJ fuel, dry bulb temperature of 25°C, with dry cooling and steam conditions as shown.

It is noted that Johnson (2005) reported a GGI 0.68 t CO_2/MWh for Integrated Gasification Combined Cycle (IGCC) plant with black coal.

- **Table 6-2 GES Technical Guidelines: New Plant Standards**

Heading	Main Steam Pressure, MPa	Main / Reheat Steam Temp., °C	Greenhouse Gas Intensity, t CO_2-e/MWh
Brown Coal Supercritical	25.0	566 / 565	1.00
Brown Coal Supercritical	26.5	576 / 600	0.98
Black Coal Supercritical	27.5	605 / 613	0.78

The Class E gas turbines to be used by DGDPS, (which have a proven track record with operation on syngas), are similar to those used by existing open cycle (peaking) power plants around Australia including installations at Mortlake, Uranquinty and Laverton North Power Stations.

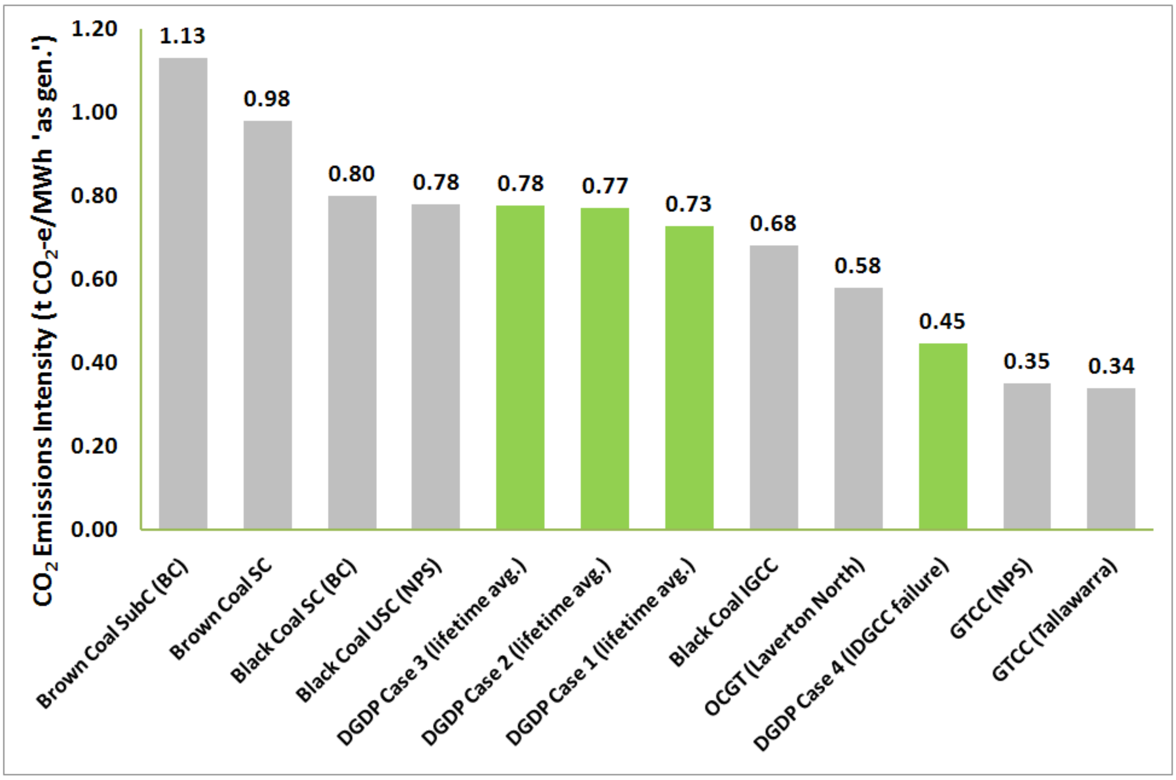
However, the proposed DGDPS will be operated in combined cycle mode (CCGT). The CCGT technique with its waste heat recovery and steam cycle is more efficient than OCGT. AGO (2006) provides new plant standards for natural gas fired CCGT and OCGT of 0.35 t CO_2 / MWh and 0.55 t CO_2 / MWh respectively.

Current operating examples of recently installed gas turbine power stations are Victoria's Laverton North OCGT and NSW's Tallawarra CCGT. The GGI of the Victoria's 312 MW Laverton North Power Station operating in OCGT mode is estimated to be 0.58 t CO_2 / MWh (SKM, 2008), assuming 1.5% used in station energy. The 435 MW-rated Tallawarra Power Station in NSW, which uses highly efficient F-class gas turbines, is estimated to have a GGI of 0.34 t CO_2/MWh (TRUenergy, 24/8/2009), assuming 1.5% used in station energy. Further discussion of E and F class gas turbine technology is presented in **Section 6.3.4** to follow.

A comparison of the DGDPS Scope 1 emissions performance results (as GGIs) with other power generation technologies is provided as **Figure 6-3** (all data sources are listed in **Appendix C**). The acronyms expanded are: BC (Best Current); CC (Carbon Capture); IGCC (Integrated Gasification Combined Cycle); NPS (New Plant Standards–AGO, 2006); SC (Supercritical); SubC (Subcritical); and USC (Ultra Super-Critical).

Inspection of **Figure 6-3** indicates that, clearly, the DGDPS's IDGCC technology represents best practice with respect to the use of brown coal (noting that the operating DGDPS will always use a combination of NG and syngas).

- **Figure 6-3 GGI: DGDPS Cases vs. Other Technologies**



6.3.4. Technology Development Pathway

The DGDPS is part of a planned technology development pathway. DGDPS has been designed using two E class gas turbines. As the provider of the IDGCC technology, HRL is also working with gas turbine suppliers to allow the use of syngas with the more efficient F class turbines in the future. **Table 6-3** shows that approximately a 12% gain in efficiency is possible from the use of F class (over E class) gas turbines operating on natural gas (sourced from Gas Turbine World, 2009 GTW Handbook).

- **Table 6-3 E Class vs. F Class Gas Turbine Performance**

Gas Turbine	F Class	E Class	Efficiency Improvement
Open Cycle Efficiency	39.3%	34.7%	11.7%
Combined Cycle Efficiency	59.7%	52.5%	12.1%

A major advantage of the DGDPS (and future plants) is that the plants will be able to be fitted with carbon capture technology, which once fitted would reduce the greenhouse intensity to approximately 0.26 t CO_2-e / MWh (DGPL estimate). The use of carbon capture is dependent upon the availability of the carbon storage site, a pipeline and its commercial viability.

Also, HRL is part of the Victorian Government's CarbonNet initiative, and CarbonNet has been shortlisted by the Commonwealth Government for funding under its $2.4 billion CCS flagships program. HRL has commenced a feasibility study of a gasification pre-combustion CO_2 capture project (refer to **Section 3.3.2**).

6.4. Scope 3 GHG Emissions Estimates

6.4.1. Overview

This section considers GHG emissions estimates for 'Scope 3' (indirect) emissions associated with energy use due to: Construction of the DGDP; and during operations: Extraction, production and transport of purchased fuels consumed by the electricity generation process; Extraction, production and transport of other purchased materials or goods during construction and operations; Employees commuting to and from work; and the Transport and disposal of waste.

6.4.2. Construction of DGDP

The GHG emissions due to construction of DGDP are expected to be small relative to those from the completed plant's operations. Therefore this section is brief, and provides a conservative (high) estimate of the GHG emissions.

It is assumed that the majority of DGDP construction materials will comprise concrete and steel. The nominal quantities for DGDP used here are 50,000 tonnes and 10,500 tonnes respectively, based on an analysis by HRLT (2009). The definition for the embodied energy of a construction material is similar to the 'Scope 3' definition provided above; *i.e.*, most of the embodied energy is due to the extraction of raw materials, the manufacture of the product and its transport to a construction site.

The GHG analysis of electricity generation systems by Dey and Lenzen (2000) provides useful, quality databases of the embodied energies of construction materials. These include the GHG contents of concrete as produced from raw materials (0.16 t CO_2-e / t, using 1.3 MJ/kg), and finished steel products from ore in the ground (3.6 t CO_2-e / t, using 40 MJ/kg). The GHG content selected for concrete compares well, and that selected for steel is conservative (high), in comparison with relevant data from the comprehensive review by Hammond and Jones (2008).

The nominal construction material amounts for DGDP, and the calculated Scope 3 GHG emissions estimate for DGDP, are provided in **Table 6-4**. The GHG emissions due to transport of construction materials to the site are expected to be small in comparison with those associated with the embodied energies of materials; *i.e.*, approximately 1% only; this is based on results for the Mt Piper power station in NSW (see SKM, 2009). As such this small amount plus other less significant components of the emissions are assumed to have been captured by the conservative (high) GHG emissions estimate of 45,000 t CO_2-e. In comparison, the SKM (2009) estimate for construction of a CCGT option for Mt Piper NSW is approximately 35,500 CO_2-e.

- **Table 6-4 GHG Emissions Estimate for Construction of DGDP**

Parameter	Quantity (Nominal)	GHG Emissions Estimates
Concrete produced from raw materials: - Embodied energy = 1.3 MJ/kg - GHG content = 0.16 t CO_2-e per tonne	50,000 tonne	8,000 t CO_2-e
Steel, finished products from ore in the ground: - Embodied energy = 40 MJ/kg - GHG content = 3.6 t CO_2-e per tonne	10,500 tonne	35,700 t CO_2-e
Total GHG emissions (Embodied energy of materials)	–	43,700 t CO_2-e
Nominal Conservative (High) Total (Accounting for other less significant components in construction)	–	45,000 t CO_2-e

6.4.3. Fuel Supply for the Operating DGDPS

The DGDPS will receive MOC via the existing M50 coal conveyor (owned and operated by Energy Brix) or YNX using diesel-powered road trucks (HRLT, 2009). For the MOC case, HRLT (*ibid.*) provided a value for electricity consumption per tonne of conveyed coal, based on a maximum of coal transported in 2006-2007.

For the YNX case, HRLT (2009) provides estimates for the amount of diesel consumption required to truck the coal to site. The input data and calculated (Scope 3) GHG emission factor is provided in **Table 6-5**.

The calculated GHG amounts using these emission factors are included in the results for the Full Fuel Cycle (see later, **Section 6.5**).

- **Table 6-5 GHG Emissions Estimates for Supply of Fuel to the Operating DGDPS**

Parameter	Fuel Usage	Relevant NGA Emission Factor	Emission Factor (kg CO_2-e / tonne coal transported)
MOC transport by M50 - electric conveyor	0.4878 kWh / tonne coal transported	1.22 kg CO_2-e / kWh	0.595
YNX transport by road - diesel truck	0.79 L / tonne coal transported (38.6 GJ/kL)	69.5 kg CO_2-e / GJ	2.12 (or 0.171 kg CO_2-e / GJ)

The DGDPS will use more than 100,000 GJ of NG per annum, therefore is classified as a large NG user (DCCEE, 2009c). The NG will be delivered to the site via gas pipeline. For Victoria, DCCEE (2009c) provides the Scope 3 CO_2-e emission factor of 4.4 kg CO_2-e/GJ. This value has been used for the GHG emissions estimates for the plant's Full Fuel Cycle (FFC); *i.e.*, Scope 1 plus Scope 3 emissions.

The calculated GHG amounts for fuel supply to the DGDPS have been included in the FFC results (**Section 6.5**).

6.4.4. Other Scope 3 Emissions

The estimate for petrol usage by the DGDP's small vehicle fleet is 10 kL/annum, thus the calculated (approximate) GHG emission rate is 25 t CO_2-e /annum. While this is a relatively small amount it has been included in the FFC results (**Section 6.5**).

Typical sources of GHG emissions associated with decommissioning include: Fuel use by equipment for dismantling the facility; *e.g.*, cranes; Crushing plant operations for breaking up concrete foundations; and Fuel use by trucks for the transport of waste materials off-site.

At the time of decommissioning is reasonable to assume that a significant amount of materials would be recycled.

Accurate GHG emissions estimates would be difficult to estimate for decommissioning of the DGDP. As such GHG estimates associated with decommissioning the DGDP have not been provided.

6.4.5. Incidental GHG Emissions

There will be other GHG emissions associated with the DGDP, however, individually and collectively, they are expected to make up very small fractions of the GHG emissions; 0.5% of total

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emissions is defined as 'incidental' within the NGERS framework. Some of these emissions sources include: Fuel use from the transport of workers and maintenance personnel to and from the site; Fuel use from demonstration power station deliveries; and Embodied emissions from chemicals and other materials associated with demonstration power station operations.

6.5. Full Fuel Cycle GHG Emissions Estimates: Scope 1 + Scope 3

The calculated annual Full-Fuel Cycle GHG mass emissions for the proposed DGDP are provided in **Table 6-6**. The results for construction and Scope 1 emissions are also listed for comparison.

- **Table 6-6 Full Fuel Cycle GHG Mass Emissions Estimates for DGDP**

DGDPS Operating Scenario	Scope 1 (kt CO_2-e / annum)	Full Fuel Cycle (kt CO_2-e / annum)	% Increase FFC over Scope 1
Construction of DGDP	n/a	45	n/a
Case 1	3,024	3,085	2.0%
Case 2	3,201	3,251	1.6%
Case 3	3,238	3,290	1.6%
Case 4	762	825	8.2%

The largest relative increase in the Scope 3 emissions is due to NG supply for Case 4 (in this case the DGDPS is assumed to run only on NG for most of its lifetime).

The calculated Full Fuel Cycle GHG emissions intensities for the DGDPS scenarios are provided in **Table 6-7**.

- **Table 6-7 Full Fuel Cycle GHG Emissions Intensities for DGDP**

DGDPS Operating Scenario	Scope 1 GGI (t CO_2-e / MWh)	FFC GGI (t CO_2-e / MWh)
Case 1	0.73	0.74
Case 2	0.77	0.78
Case 3	0.78	0.79
Case 4	0.45	0.48

7. Summary of Best Practice

7.1. Overview

This section provides a summary of the main initiatives with respect to best practice including an overview of the results of benchmarking (DGDPS vs. competing technologies).

7.2. World's Best Practice IDGCC Technology for Victoria

The proposed DGDPS facility using IDGCC technology developed by HRL, represents world's best practice with respect to utilisation of brown coal for electricity generation.

The DGDPS will offer significantly lower greenhouse gas emissions per unit of electricity generated than existing sub-critical brown coal fired power stations in the Latrobe Valley. Also, the DGDPS emissions performance is expected to be better than that of 'supercritical brown coal'.

The DGDPS Cases 1–3 (the IDGCC success cases) have project average GGIs ranging from 0.73–0.78 t CO_2-e / MWh, which are lower than those for all existing black coal-fired power stations in Australia, including existing super-critical black coal power stations.

Also, Cases 1 and 2 perform better than the new plant standard of 0.78 t CO_2-e / MWh (AGO, 2006) for ultra-super critical black coal power station (fired with a 90.1 kg CO_2 / GJ black coal, a dry bulb temperature of 25°C and with dry cooling). Case 3 has the same performance.

The flexibility of the DGDPS, allowing the use of lower greenhouse intensive natural gas as well as the abundant and (currently) lower cost brown coal also avoids the potential of an emissions lock-in for a 30-year plus project.

The DGDPS provides a technology pathway for lower emissions from brown coal. As the provider of the IDGCC technology, HRL is also working with gas turbine suppliers to allow the use of syngas with the more efficient F class turbines in the future, (in comparison with E class turbines selected for the DGDPS), which is expected to result in a 12% gain in efficiency.

With respect to best practice in the reduction of greenhouse gas emissions, the proposed DGDPS represents a markedly improved technology for producing electricity from brown coal. The improvement is due to the integrated drying and coal gasification allowing for improved brown coal emissions performance. It also provides a future technology development pathway for lower CO_2 emissions performance for the generation of power from brown coal.

7.3. Potential for Carbon Capture

7.3.1. Carbon Capture for DGDPS

Carbon Capture and Storage (CCS) is a group of technologies for capturing the CO_2 emitted from power plants and industrial sites, compressing this CO_2 and transporting it to suitable permanent storage sites such as deep geological formations.

The future retro-fitting of carbon capture technology to DGDPS (if commercially viable), is expected to enable the facility to achieve an expected greenhouse gas intensity of approximately 0.26 t CO_2-e / MWh (DGPL). Importantly, installation of high efficiency power generation technology will minimise the quantity of carbon dioxide requiring capture, as is the case for DGDPS (or future IDGCC power stations).

The use of carbon capture is dependent upon the availability of the carbon storage site, a pipeline and its commercial viability.

7.3.2. CarbonNet

A multi-user CO_2 capture, transport and storage infrastructure proposal for the Latrobe Valley, (CarbonNet), is one of four projects shortlisted under the Australian Government's CCS Flagships Program. CarbonNet involves the development of a series of pipelines from high CO_2 emitters in the Latrobe Valley to geological carbon storage sites in proven offshore and onshore areas in Victoria; *e.g.*, Minister for Energy and Resources (2009). The Minister *(ibid.*) stated that the proposal would see Victoria become the location for one of the 20 large-scale carbon capture, transport and storage projects required worldwide, outlined by the G8 as being essential to reduce future global CO_2 emissions (refer to **Section 3.3.2** and **Section 0**).

As part of CarbonNet, on 20th January 2010 the Victorian Government announced funding of up to $29 million for pre-feasibility studies to be shared among five projects, the first to receive ETIS funding for new large-scale, pre-commercial CCS demonstration projects in Victoria (Minister for Energy and Resources, 2010).

HRL is part of the Victorian Government's proposal for CarbonNet. The Victorian Government funding includes up to $3.5 million to investigate the feasibility of a gasification, pre-combustion CO_2 capture project being developed by HRL. Remaining funding of $110 million will be allocated to projects that successfully meet expectations (Minister for Energy and Resources, *ibid.*).

7.3.3. Capture Technology Costs and Implementation Trigger

The trigger point for the implementation of carbon capture will be when the technology is technically proven and commercially viable. To be commercially viable the costs and risks of implementation need to be lower than the benefits of carbon capture.

Although currently CCS technology is not economically feasible, a key element of managing CO_2 emissions would be the implementation of a process to periodically review technologies and their viability in order to plan appropriately for their eventual implementation at the proposed DGDPS. This review process would incorporate potential trigger points for implementation of CCS.

7.4. Practical On-Site Energy Savers (EPA Victoria)

This section details some smaller but practical actions that will be undertaken by DGPL in the final design, construction and operating phases of DGDP; *e.g.*, see EPA publications 1157, 1160 and 1164 which provide similar measures adopted by industry.

- Install variable speed drives on pumps and other equipment.
- Optimise boiler performance with regular maintenance and tuning and consider insulation, fixing steam leaks and installing economisers.
- Optimise compressed air systems through insulation, fixing air leaks, optimising operating pressures, design and installation of the most appropriate type and size of compressor(s) to suit the identified usage quantities and patterns.
- Design and install energy efficient lighting systems and remove unnecessary lighting.
- Ensure hot water system/s are insulated and running at an optimal temperature.
- Explore heat recovery options in industrial processes, such as collecting condensate for use as feedwater for boiler or using waste heat for space heating.
- Assess heating, ventilation and air conditioning systems. Consider optimising thermostat settings depending on the weather, (*e.g.*, 26 °C in summer and 18 °C in winter). Ensure systems are switched off out of operating hours.
- Regularly review plant equipment – upgrading equipment can often improve productivity and deliver energy savings.

7.5. HRL Limited's History of Emissions Management Initiatives

The objective of the Generator Efficiency Standards (GES) measure is to encourage best practice in the efficiency of fossil-fuelled electricity generation and to reduce the GHG intensity of energy supply. The GES measure applies to all fossil-fuelled power generation plants with an electrical capacity of 30MW or more and with an annual electrical output of 50GWh per year.

HRL, through EBAC, participated in GES (and the Greenhouse Challenge program), assessing its operations and comparing these with best practice as set out in the GES Technical Guidelines.

HRL's emissions management initiatives including its involvement in GES and research activities are set out in detail in **Section 3.4**.

8. Conclusions

A greenhouse gas assessment was undertaken to form part of the Works Approval Application for the Dual Gas Demonstration Project proposed for the Latrobe Valley, Victoria.

It is expected that the proposed Dual Gas Demonstration Power Station (DGDPS) will generate approximately 600 MW of electrical power and will demonstrate the Integrated Drying and Gasification Combined Cycle (IDGCC) technology at commercial scale. The proposed DGDPS is located within the existing Energy Brix Australia Corporation site at Morwell, in Victoria.

The DGDPS does not use conventional brown coal-fired power station technology.

The DGDPS design includes two Integrated Drying and Gasification units, or 'gasifiers', to provide synthesis gas (syngas) to fuel two Combined Cycle Gas Turbines. It is fuelled by syngas generated from brown coal, with hydrogen gas the main energy component of syngas. Methane is the main energy component for natural gas. Natural gas will be used as a start-up and supplementary fuel for the DGDPS and normal operations by the DGDPS will include some use of natural gas.

This assessment has focussed on the average greenhouse gas emissions performance over the projected 30-year life of the DGDPS.

The exact amounts of coal and natural gas used each year will be influenced by the nature and structure of long term fuel supply contracts, electricity supply contracts, spot (short term) gas costs and electricity prices, and any cost placed on carbon emissions. Electricity prices will be influenced by electricity demand and supply (including plant retirements) and government policy.

Four case study operating scenarios have been modelled for the DGDPS covering the expected range of emissions performance for the facility on an as generated basis. The cases are described, including fuel usage details, in the following table and cover a range of potential syngas and natural gas fuel mix scenarios. Cases 1-3 are IDGCC success scenarios and Case 4 is an IDGCC non-success scenario. The expectation is that the DGDPS will commence using one gasifier in 2013 and that a second gasifier will be added in 2015. The second gasifier will incorporate lessons learned from the first gasifier.

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DGDPS Operating Scenario	Coal Source and Syngas Usage	Natural Gas Usage	Average annual GHG Emissions (kt CO_2-e p.a.)	Project Average Greenhouse Gas Emissions Intensity 'as generated' (t CO_2-e / MWh)
Case 1	Two gasifiers fuelled by: • MOC syngas from 2012/13–2015/16 • YNX syngas from 2016/17 to 2026/27 • MOC syngas from 2027/28–2041/42	A large amount of NG used throughout lifetime.	3,024	0.73
	Average coal usage: 2,345 kT p.a.	Average 11,425 TJ p.a.		
Case 2	Two gasifiers fuelled by: • MOC syngas from 2012/13–2015/16 • YNX syngas from 2016/17 to 2026/27 • MOC syngas from 2027/28–2041/42	A moderate amount of NG throughout lifetime.	3,201	0.77
	Average coal usage 2,636 kT p.a.	Average 8,715 TJ p.a.		
Case 3	Two gasifiers fuelled by MOC syngas over 30-year lifetime	A moderate amount of NG throughout lifetime.	3,238	0.78
	Average coal usage 2,803 kT p.a.	Average 9,518 TJ p.a.		
Case 4 note*	MOC syngas-fuelled by single gasifier ceasing after 4 years in 2015/16	DGDPS fuelled by NG only from 2016/17–2041/42.	762	0.45
	MOC coal usage average 322 kT p.a. (average of first 4 years only)	Average 14,108 TJ p.a.		

Note* In the event that the IDGCC technology is found to be unfeasible (at commercial scale), after approximately the first four years, the facility would revert to be wholly natural gas fired with a corresponding lower GGI of approximately 0.43 t CO_2-e / MWh.

The flexibility of the DGDPS, allowing the use of lower greenhouse intensive natural gas as well as the abundant and (currently) lower cost brown coal, avoids the potential of an emissions lock-in for the 30-year plus project.

The average greenhouse gas emission for the three IDGCC success scenarios (Cases 1 – 3), over the DGDPS's 30-year life, is expected to range between 3.0 – 3.2 million tonnes of carbon dioxide equivalent (Mt CO_2-e) per annum.

The theoretical maximum greenhouse gas emission for the proposed DGDPS is calculated to be 4.2 million tonnes of carbon dioxide equivalent (Mt CO_2-e) per annum, however is very unlikely to occur given expected normal operating and market conditions.

This assessment has found that, for the three DGDPS success scenarios studied, on an annual basis over its projected 30-year life the DGDPS greenhouse gas intensity is expected to range between 0.73 – 0.78 t CO_2-e / MWh, depending on the fuel mix.

The Victorian Government's *Victorian Climate Change White Paper - The Action Plan*, (July 2010), sets a target greenhouse gas intensity of 0.8 t CO_2-e / MWh for new power stations. The DGDPS's emissions performance complies with this benchmark.

Comparison of DGDPS performance against existing power stations and 'best practice' power generation technology, is calculated using publicly available GGI on a 'sent out' basis and adjusting these by an estimated factor for electricity consumed by the power station.

The greenhouse gas intensities for the larger brown coal-fuelled power stations in the Latrobe Valley are listed below (there are slight variations from year-to-year):

Heading	Greenhouse Gas Intensity (t CO_2-e / MWh "Sent Out")	Estimated Electricity Percentage Used Internally	Greenhouse Gas Intensity (t CO_2-e / MWh "Generated"
Hazelwood Power Station	1.52	8 %	1.40
Yallourn Power Station	1.42	8 %	1.31
Loy Yang A	1.21	7 %	1.12
Loy Yang B	1.23	7 %	1.14

This assessment has found that the proposed DGDPS success cases studied will have greenhouse gas intensities significantly less (31% - 36%) than the best current brown coal power station (Loy Yang A) with variations depending on the coal quality and amounts of syngas and natural gas used by DGDPS each year.

Clearly, comparisons of the DGDPS GGIs with those of the existing brown coal power stations (listed above) show that the DGDPS will offer significantly better GGIs than the best current sub-critical brown coal fired power station in the Latrobe Valley.

Also, the DGDPS is expected to exceed the performance standard for 'supercritical brown coal'; *i.e.*, 0.98 t CO_2-e / MWh (AGO, 2006).

The DGDPS is expected to have a lower project average GGI than all existing black coal power stations in Australia.

The DGDPS provides a technology pathway for lower emissions from brown coal.

The DGDPS has been designed to enable the potential retrofit of CO2 capture technology when commercially viable. The proposed site layout includes space reserved for the potential carbon capture plant to be located. The retro-fitting of carbon capture technology is expected to lower the GGI to well below best practice natural gas combined cycle.

HRL has estimated the current annual CO_2-e emissions of Latrobe Valley brown coal-fired power stations to be approximately 57 Mt per annum. If new IDGCC technology with a GGI of 0.73 t CO_2-e / MWh was to displace the current fleet of brown coal power stations, this would result in annual savings of approximately 24 Mt of CO_2-e emissions per annum (a 42% reduction in these emissions in the Latrobe Valley). HRL estimates that a further savings of approximately 21 Mt per annum would be achieved with the development and implementation of carbon capture and storage technologies. The total annual savings of 45 Mt CO_2-e would equate to 8.3% of the total Australian CO_2 emissions (based on 2007 data).

In conclusion, with respect to the need to reduce greenhouse gas emissions, this assessment has found that the proposed DGDPS represents a markedly improved technology for producing electricity from brown coal. The improvement is due to integrated drying and gasification of brown coal allowing for improved brown coal emissions performance, supplemented by the lower emissions performance of natural gas. It also provides a future technology development pathway for lower CO_2 emissions performance for the generation of power from brown coal.

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9. References

This section provides a list of general references; additional references used for performance comparisons are provided separately in **Appendix C**, 'Sources of Data for Comparisons'.

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Appendix A DGDPS Fuel Input Scenarios

This Appendix provides the HRLT (2010a) data for annual variations in coal and Natural Gas (NG) amounts for the four potential future DGDPS operating scenarios investigated for this assessment. These data were used as inputs for estimates of annual greenhouse gas emissions (see table overleaf).

The four case studies are described in brief in the table below.

DGDPS Operating Scenario	Coal Source and Syngas Usage	Natural Gas Usage
Case 1	Two gasifiers fuelled by: • MOC syngas from 2012/13–2015/16 • YNX syngas from 2016/17 to 2026/27 • MOC syngas from 2027/28–2041/42	A large amount of NG used throughout lifetime.
	Average coal usage: 2,345 kT p.a.	Average 11,425 TJ p.a.
Case 2	Two gasifiers fuelled by: • MOC syngas from 2012/13–2015/16 • YNX syngas from 2016/17 to 2026/27 • MOC syngas from 2027/28–2041/42	A moderate amount of NG throughout lifetime.
	Average coal usage 2,636 kT p.a.	Average 8,715 TJ p.a.
Case 3	Two gasifiers fuelled by MOC syngas over 30-year lifetime	A moderate amount of NG throughout lifetime.
	Average coal usage 2,803 kT p.a.	Average 9,518 TJ p.a.
Case 4	MOC syngas-fuelled by single gasifier ceasing after 4 years in 2015/16	DGDPS fuelled by NG only from 2016/17–2041/42.
	MOC coal usage average 322 kT p.a. (average of first 4 years only)	Average 14,108 TJ p.a.

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A.1 Annual Fuel Variations for 4 Potential Future DGDPS Operating Scenarios

	Case 1		Case 2		Case 3		Case 4	
FY	Coal (kT)	NG (TJ)	Coal (kT)	NG (TJ)	Coal (kT)	NG (TJ)	Coal (kT)	NG (TJ)
2012/13	127	4,948	127	4,948	127	4,948	31	5,309
2013/14	1,050	11,482	1,050	11,482	1,050	11,482	310	13,719
2014/15	1,602	13,165	1,335	13,256	1,335	13,256	516	16,136
2015/16	2,277	13,386	1,976	12,139	1,938	12,420	431	16,786
2016/17	2,051	11,765	2,361	8,150	2,788	9,992	0	16,697
2017/18	2,180	11,408	2,565	7,325	3,019	9,384	0	16,152
2018/19	2,198	10,779	2,621	6,421	3,063	8,606	0	14,936
2019/20	2,263	11,865	2,737	7,193	3,207	9,441	0	17,444
2020/21	2,257	12,583	2,771	7,807	3,243	10,053	0	19,949
2021/22	2,257	12,443	2,771	7,668	3,243	9,908	0	20,008
2022/23	2,257	12,702	2,771	7,927	3,243	10,165	0	20,355
2023/24	2,263	12,772	2,779	7,984	3,252	10,226	0	20,530
2024/25	2,031	11,274	2,493	6,979	2,910	9,015	0	18,307
2025/26	2,257	12,769	2,771	7,994	3,243	10,228	0	20,584
2026/27	2,257	12,730	2,771	7,955	3,243	10,191	0	20,452
2027/28	2,762	12,450	3,042	10,398	3,042	10,398	0	15,997
2028/29	2,755	11,378	3,034	9,331	3,034	9,331	0	11,683
2029/30	2,755	11,263	3,034	9,217	3,034	9,217	0	11,266
2030/31	2,703	10,804	2,976	8,797	2,976	8,797	0	10,593
2031/32	2,762	11,192	3,042	9,140	3,042	9,140	0	10,925
2032/33	2,755	11,141	3,034	9,095	3,034	9,095	0	10,823
2033/34	2,755	11,001	3,034	8,955	3,034	8,955	0	10,630
2034/35	2,755	11,102	3,034	9,056	3,034	9,056	0	10,681
2035/36	2,762	11,123	3,042	9,071	3,042	9,071	0	10,675
2036/37	2,472	9,865	2,722	8,030	2,722	8,030	0	9,464
2037/38	2,755	11,092	3,034	9,046	3,034	9,046	0	10,645
2038/39	2,755	11,092	3,034	9,046	3,034	9,046	0	10,645
2039/40	2,762	11,004	3,042	8,952	3,042	8,952	0	10,554
2040/41	2,755	11,092	3,034	9,046	3,034	9,046	0	10,645
2041/42	2,755	11,092	3,034	9,046	3,034	9,046	0	10,645

Appendix B Results – DGDPS Greenhouse Gas Emissions

This Appendix provides the detailed set of results for greenhouse gas emissions estimates for four potential future operating scenarios for DGDPS.

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B.1 Case 1: MOC-YNX-MOC syngas and NG-fuelled DGDPS

Financial Year	Total Emission (kt CO_2-e)	Generated Electricity (GWh)	GHG Intensity (t CO_2-e / MWh 'generated')
2012/13	377.2	717	0.526
2013/14	1,617.2	2,468	0.655
2014/15	2,244.6	3,282	0.684
2015/16	2,919.5	4,082	0.715
2016/17	2,966.2	4,209	0.705
2017/18	3,096.7	4,346	0.713
2018/19	3,084.6	4,300	0.717
2019/20	3,215.1	4,520	0.711
2020/21	3,244.7	4,595	0.706
2021/22	3,237.5	4,579	0.707
2022/23	3,250.8	4,609	0.705
2023/24	3,261.5	4,626	0.705
2024/25	2,917.3	4,129	0.706
2025/26	3,254.2	4,617	0.705
2026/27	3,252.2	4,613	0.705
2027/28	3,348.0	4,517	0.741
2028/29	3,285.9	4,384	0.750
2029/30	3,280.0	4,370	0.751
2030/31	3,205.4	4,258	0.753
2031/32	3,283.8	4,370	0.751
2032/33	3,273.8	4,356	0.752
2033/34	3,266.7	4,339	0.753
2034/35	3,271.8	4,351	0.752
2035/36	3,280.3	4,362	0.752
2036/37	2,930.7	3,893	0.753
2037/38	3,271.3	4,350	0.752
2038/39	3,271.3	4,350	0.752
2039/40	3,274.2	4,348	0.753
2040/41	3,271.3	4,350	0.752
2041/42	3,271.3	4,350	0.752
Lifetime average			0.73

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B.2 Case 2: MOC-YNX-MOC syngas and NG-fuelled DGDPS

Financial Year	Total Emission (kt CO_2-e)	Generated Electricity (GWh)	GHG Intensity (t CO_2-e / MWh 'generated')
2012/13	377.2	717	0.526
2013/14	1,617.2	2,479	0.652
2014/15	1,987.3	2,994	0.664
2015/16	2,560.1	3,558	0.720
2016/17	3,138.6	4,150	0.756
2017/18	3,332.0	4,330	0.770
2018/19	3,350.2	4,300	0.779
2019/20	3,523.5	4,547	0.775
2020/21	3,593.9	4,665	0.770
2021/22	3,586.7	4,648	0.772
2022/23	3,600.0	4,679	0.769
2023/24	3,611.6	4,695	0.769
2024/25	3,231.4	4,192	0.771
2025/26	3,603.4	4,686	0.769
2026/27	3,601.4	4,682	0.769
2027/28	3,518.0	4,548	0.774
2028/29	3,455.3	4,414	0.783
2029/30	3,449.5	4,401	0.784
2030/31	3,371.6	4,289	0.786
2031/32	3,453.7	4,401	0.785
2032/33	3,443.3	4,387	0.785
2033/34	3,436.1	4,371	0.786
2034/35	3,441.3	4,382	0.785
2035/36	3,450.2	4,393	0.785
2036/37	3,082.7	3,921	0.786
2037/38	3,440.8	4,381	0.785
2038/39	3,440.8	4,381	0.785
2039/40	3,444.1	4,379	0.786
2040/41	3,440.8	4,381	0.785
2041/42	3,440.8	4,381	0.785
Lifetime average			0.77

B.3 Case 3: MOC syngas and NG-fuelled DGDPS

Financial Year	Total Emission (kt CO_2-e)	Generated Electricity (GWh)	GHG Intensity (t CO_2-e / MWh 'generated')
2012/13	377.2	717	0.526
2013/14	1,617.2	2,479	0.652
2014/15	1,987.3	2,994	0.664
2015/16	2,536.9	3,554	0.714
2016/17	3,248.0	4,199	0.774
2017/18	3,443.2	4,378	0.786
2018/19	3,447.1	4,337	0.795
2019/20	3,630.8	4,591	0.791
2020/21	3,697.7	4,702	0.786
2021/22	3,690.2	4,685	0.788
2022/23	3,703.3	4,715	0.785
2023/24	3,715.2	4,732	0.785
2024/25	3,317.2	4,218	0.787
2025/26	3,706.6	4,722	0.785
2026/27	3,704.7	4,718	0.785
2027/28	3,518.0	4,548	0.774
2028/29	3,455.3	4,414	0.783
2029/30	3,449.5	4,401	0.784
2030/31	3,371.6	4,289	0.786
2031/32	3,453.7	4,401	0.785
2032/33	3,443.3	4,387	0.785
2033/34	3,436.1	4,371	0.786
2034/35	3,441.3	4,382	0.785
2035/36	3,450.2	4,393	0.785
2036/37	3,082.7	3,921	0.786
2037/38	3,440.8	4,381	0.785
2038/39	3,440.8	4,381	0.785
2039/40	3,444.1	4,379	0.786
2040/41	3,440.8	4,381	0.785
2041/42	3,440.8	4,381	0.785
Lifetime average			0.78

SKM

B.4 Case 4: IDGCC 'non-success case', mainly NG-fuelled DGDPS

Financial Year	Total Emission (kt CO_2-e)	Generated Electricity (GWh)	GHG Intensity (t CO_2-e / MWh 'generated')
2012/13	301.4	658	0.458
2013/14	1,005.1	1,950	0.516
2014/15	1,330.6	2,456	0.542
2015/16	1,279.9	2,440	0.524
2016/17	852.3	1,964	0.434
2017/18	824.5	1,900	0.434
2018/19	762.4	1,757	0.434
2019/20	890.4	2,052	0.434
2020/21	1,018.3	2,347	0.434
2021/22	1,021.3	2,354	0.434
2022/23	1,039.0	2,395	0.434
2023/24	1,047.9	2,415	0.434
2024/25	934.5	2,154	0.434
2025/26	1,050.7	2,422	0.434
2026/27	1,043.9	2,406	0.434
2027/28	816.6	1,882	0.434
2028/29	596.4	1,374	0.434
2029/30	575.1	1,325	0.434
2030/31	540.7	1,246	0.434
2031/32	557.7	1,285	0.434
2032/33	552.5	1,273	0.434
2033/34	542.6	1,251	0.434
2034/35	545.2	1,257	0.434
2035/36	544.9	1,256	0.434
2036/37	483.1	1,113	0.434
2037/38	543.4	1,252	0.434
2038/39	543.4	1,252	0.434
2039/40	538.7	1,242	0.434
2040/41	543.4	1,252	0.434
2041/42	543.4	1,252	0.434
Lifetime average			0.45

Appendix C Sources of Data for Comparisons

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Appendix E Noise Assessment

Noise Level Prediction Modelling for the Dual Gas Demonstration Project

ENVIRONMENTAL NOISE MODELLING

- Final
- 19 July 2010

Noise Level Prediction Modelling for the Dual Gas Demonstration Project

ENVIRONMENTAL NOISE MODELLING

- Final
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Contents

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Glossary

Term	Description
dB	Decibel – Sound Pressure Level expressed in decibels is 20 log of the ratio between the measured sound pressure level and the reference pressure. The reference pressure is 0.000002 Pascal (Newtons per square meter), the threshold of hearing.
dB(A)	A Sound Pressure Level where the sound is filtered in accordance with the A-weighting scale. The A weighting scale is a weighting scale which generally corresponds to the inverse of the 40 dB (at 1 kHz) equal-loudness curve. The A weighting parallels the sensitivity of the human ear when it is exposed to normal levels.
L_{A10}	The A weighted sound pressure level that is exceeded for 10% of the measurement period (approximately the average maximum noise level)
L_{A90}	The A weighted sound pressure level that is exceeded for 90% of the measurement period (represents the background noise level)
L_{Aeq}	The equivalent continuous sound level. The steady dB(A) level which would produce the same A weighted sound energy over a stated period of time as the specified time – varying sound.
Day Period	The time between 0700 and 1800 hours
Evening Period	The time between 1800 and 2200 hours
Night Period	The time between 2200 and 0700 hours

Executive Summary

SKM was commissioned by Dual Gas Pty Ltd to conduct an assessment to determine the acoustic impact of the proposed Dual Gas Demonstration Project in the Latrobe Valley, south of Morwell. The assessment forms part of the EPA Works Approval application to be submitted by Dual Gas Pty Ltd.

The assessment comprised of an environmental noise survey to determine existing background noise levels in the vicinity of the site and computer modelling of the proposed site and equipment to predict the noise levels. The potential acoustic impact in the neighbouring residential community that might result from the operation of the proposed power station was also assessed.

The noise levels due to the plant are predicted to comply with the night time RMNL at No.30 Church. St, Hazelwood for the 'worst case', neutral and prevailing meteorological conditions even allowing for the elevated background noise levels at this location due to the timber mill.

However, the noise level prediction results indicate that the night time RMNL will be exceeded by of the order of 5 dBA for the 'worse case' meteorological conditions at No. 46 McLean Road, Morwell.

Very little Sound Power Level data was available for the prediction process so best estimates were included in the current modelling. We note that the client has committed to perform the necessary noise mitigations on the various noise sources so as to ensure compliance of the noise levels emitted by the plant with the EPA noise limit criteria. However, it will be necessary to verify the Sound Power Level data prior to committing to any noise mitigation program.

1. Introduction

Dual Gas Pty Ltd is proposing to develop a demonstration power station using Integrated Drying and Gasification Combined Cycle (IDGCC) technology, which will generate approximately 600MW of power for sale in the National Electricity Market (NEM). The power station will be fuelled primarily by synthetic gas produced from brown coal with a supplementary fuel of natural gas.

SKM was commissioned to perform an environmental noise survey to determine existing background noise levels and to also perform computer modelling of the proposed site and equipment with a view to predicting the potential acoustic impact in the neighbouring residential community that might result from the operation of the proposed power station. The assessment forms part of the EPA Works Approval application to be submitted by Dual Gas Pty Ltd.

This report presents the results of the background noise level monitoring and also of the noise prediction modelling for the proposed Dual Gas Demonstration Project.

SINCLAIR KNIGHT MERZ
SKM

2. Background

2.1. Proposed Site

The proposed Dual Gas Demonstration Project site is located south of the Morwell township, which is approximately 150 km southeast of Melbourne's Central Business District.

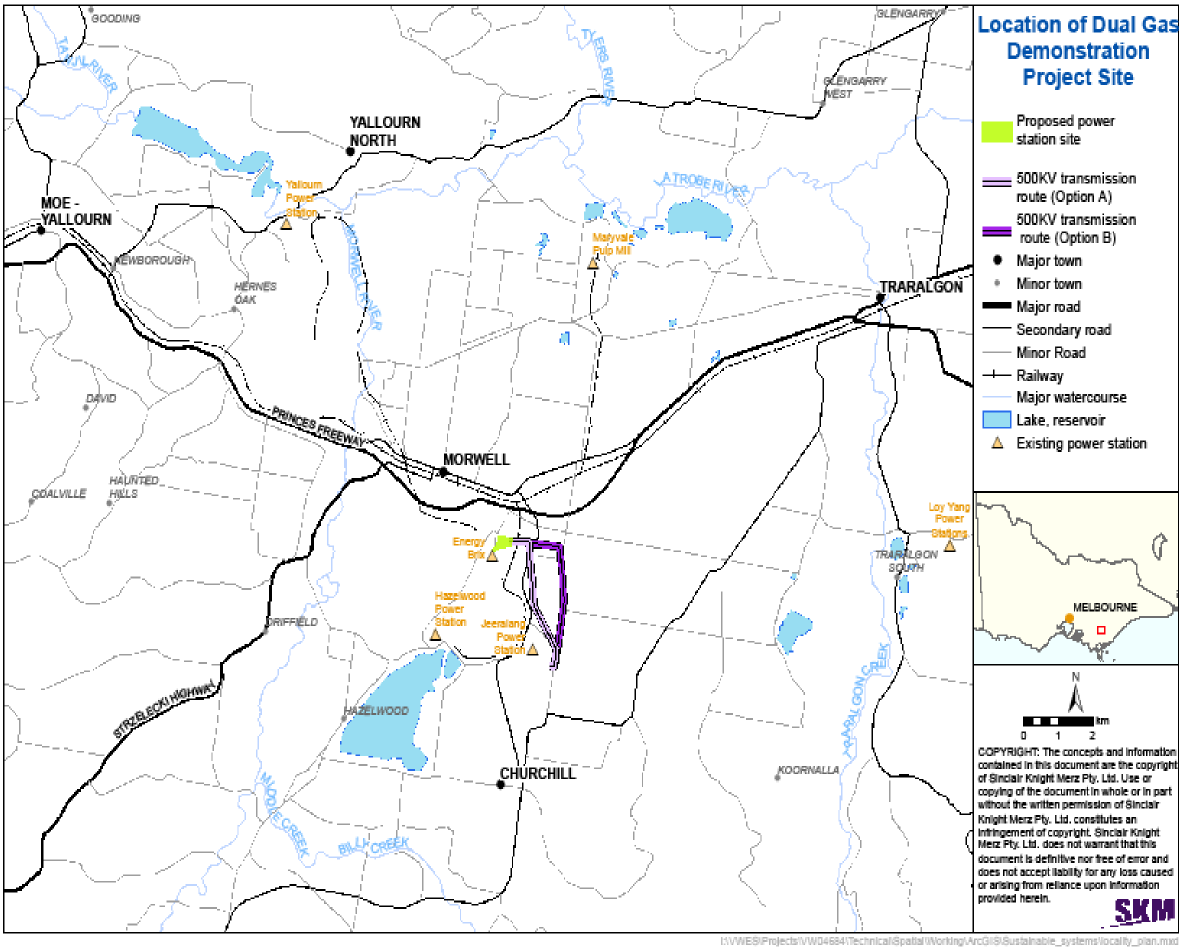

Figure 2-1 Proposed Site for the Gasification Plant and Power Station Showing Location of Nearest Townships.

The demonstration power station site is to be located on an existing open aired briquette storage area and car park within the Energy Brix Australia Corporation (EBAC) site as shown in Figure 2-2. The EBAC site is bounded to the west by Monash Way and to the north by Commercial Road.

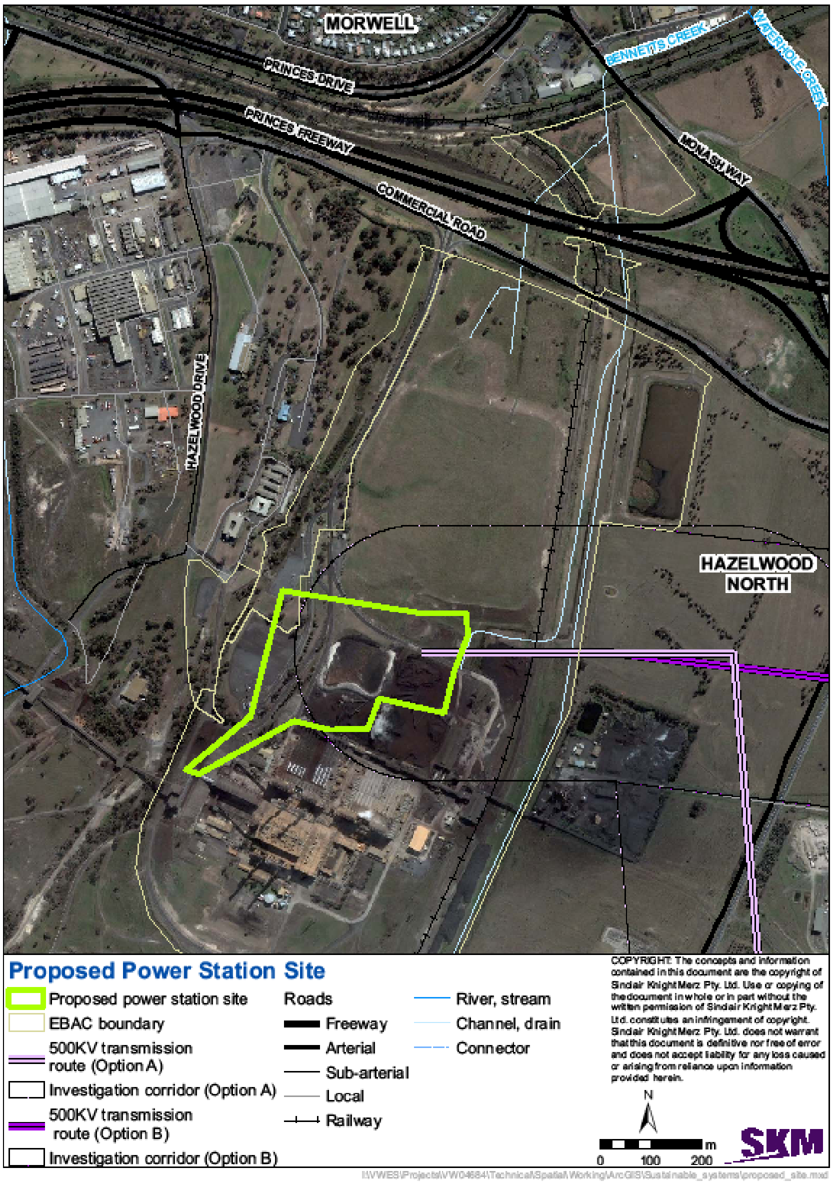

Figure 2-2 Proposed Power Station Site

The majority of the site is affected by a Special Used Zone – Schedule 1 (Brown Coal) (SUZ1) under the Latrobe Planning Scheme.

The northwest corner of the site will be an office building and a part of a car park associated with the proposed power station.

The site will be accessed via a private road off Commercial Road.

2.2. Proposed Plant Equipment

The following plant and equipment is proposed for the power station:

- 2 integrated drying and gasification plants including;
  - Syngas filtration and conditioning plant;
  - Air compressors;
  - Char and ash combustion plant;
  - By-product drying and crystallisation plant
- 2 gas turbines (GTs);
- 2 heat recovery steam generators (HRSGs);
- 1 steam turbine and generator (STG);
- 1 air cooled condenser (ACC);

The height of the combined cycle power plant stacks is estimated to be approximately 80 metres, with the final height to be determined mainly by technical and air quality requirements.

The heights of other major noise sources in the proposed power station complex were assumed as follows:

- Gasification plant - All drives and other noise sources were modelled at ground level and having a height of 3 metres
- Syngas Conditioning System – All noise emitters were located at ground level and had a maximum height of 3 metres
- Gas Turbines, Heat Recovery Steam Generators - height of 23 metres
- Steam Turbine Generator Hall - height of 31 metres
- Air Cooled Condensers - height of 47 metres

The following connection of utilities and minor construction activities will also be conducted as part of the construction activities associated with the proposed power station development.

- Installation of ash water disposal pipeline from the char burner to the an existing ash management facility located approximately 700 metres south of the proposed demonstration power station site (via EBAC owned land)
- Construction of a coal supply conveyor from the EBAC raw coal bunker adjacent to the south west corner of the proposed power station site

- Tap into an existing main water supply pipeline located approximately 100 metres west of the proposed demonstration power station site (via EBAC owned land)
- Connection of utilities, including electricity and gas supplies
- Construction of administrative building
- Construction of additional car parking facilities
- Construction of proposed site drainage and water management systems
- Security fencing and landscaping

The construction of all the plant and utilities listed above except for the Integrated Drying and Gasification Plant No. 2 is expected to be completed and commissioned and to be supplying full generation capacity to the grid by 2013. The construction of the Integrated Drying and Gasification Plant No. 2 is expected to be completed and commissioned by 2015, subject to the demonstration of acceptable performance from the Combined Cycle units and Integrated Drying and Gasification Plant No. 1.

Figure 2-3 below shows the proposed locations for the key plant, buildings and infrastructure connection points.

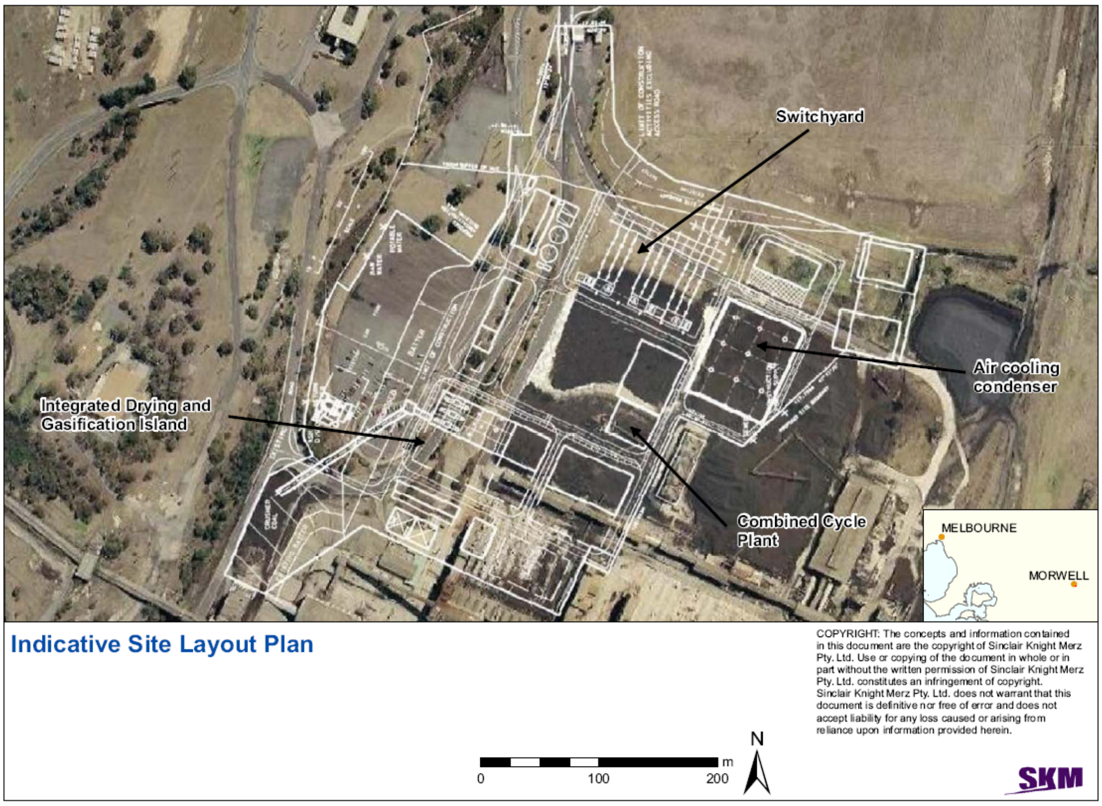

Figure 2-3 Indicative Site Layout Plan

2.3. Operation

2.3.1. Power Generation

The proposed power station will be operated as a base-load power station, generating approximately 600 MW of power in the combined cycle power generation systems (GTs in combination with HRSGs and STs) to be sent out to the 500kV transmission grid for sale in the National Electricity Market (NEM).

The primary fuel used in the power generation will be synthetic gas (syngas) generated from brown coal. Natural gas is expected to be used as start-up fuel, as well as a supplementary fuel to be used when adequate syngas (in quality and quantity) is not available.

The Gas Turbines will generate power when firing syngas, natural gas, or a combination of both gases. Additional power is to be generated by a Steam Turbine, powered by steam raised by:

- Heat Recovery Steam Generators fired by the GT exhausts, with supplementary heat input from natural gas firing; and
- Combustion of char and ash residues from the gasification plant.

It is expected that the power plant will operate at a 95% capacity factor. The completed demonstration power station, i.e. after the construction of the 2nd Integrated Drying and Gasification Plant, is expected to run 85% of the time by syngas and 10% by natural gas.

2.3.2. Syngas Production

Syngas for use in the Gas Turbiness will be generated by the IDGCC technology, where:

- Coal is dried under pressure by hot syngas
- Hot syngas is generated by gasification of the dried coal;
- Hot syngas is cooled by the drying of the coal; and
- Cooled syngas is filtered and conditioned, suitable for combustion in the GTs.

It is expected that coal will be sourced from an existing mine adjacent to the proposed demonstration power station site. The coal will be delivered from the mine to the EBAC site via existing conveyors, then to the proposed demonstration power station site via a new conveyor. Alternative coal may need to be sourced from other Latrobe Valley brown coal mines from mid 2016. At the time of this Works Approval application, it is assumed that from mid 2016 coal will be sourced from the Yallourn North Extension coal mine, which is located approximately 10 kilometres northwest of the proposed power station site and delivered to the existing EBAC coal ditch bunker by road trucks.

Figure 2-4 below shows the operational flows for the proposed power station using IDGCC process.

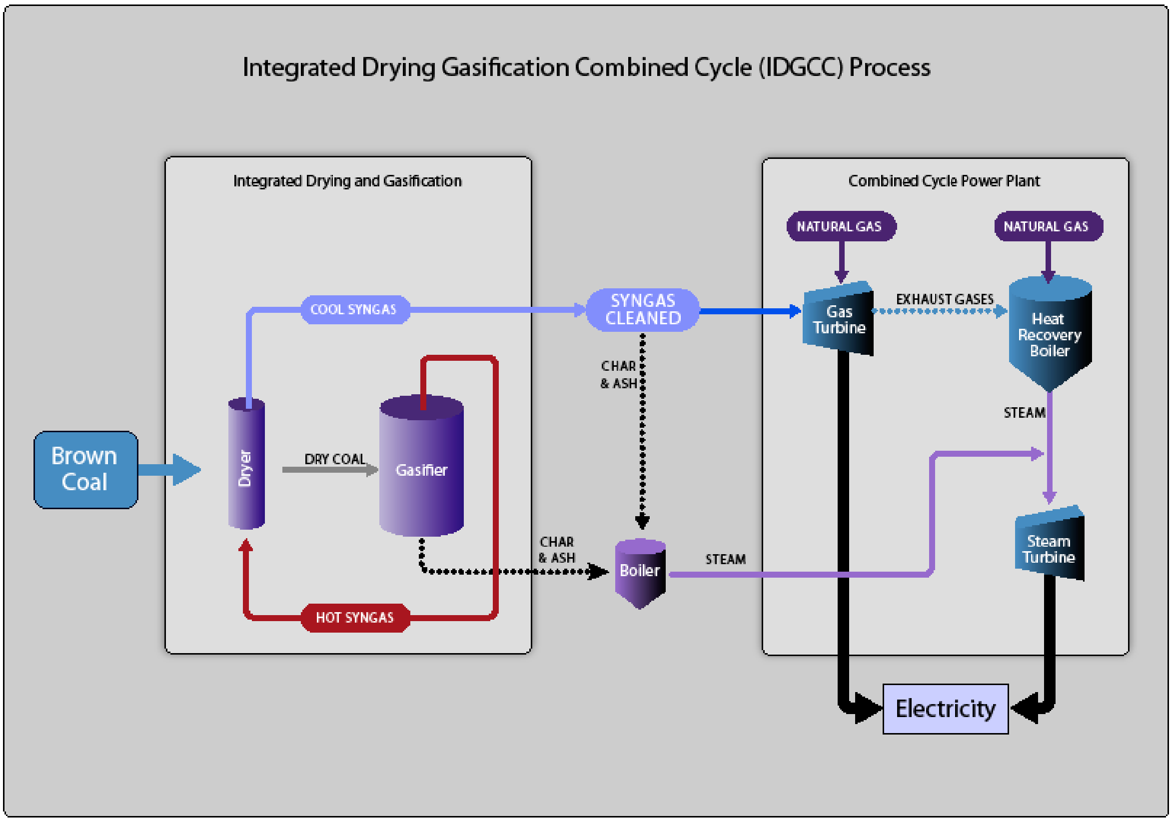

Figure 2-4 IDGCC Process and Power Station Flow Diagram

3. Methodology

3.1. Environmental Background Noise Survey

Environmental noise level measurements were conducted from 15th to 22nd October, 2009 in the vicinity of the site to determine the typical background noise levels.

The background noise level measurements were conducted continuously over a seven day measurement period in accordance with the requirements of the SEPP EPA No N-1 Noise Policy titled ‘State Environment Protection Policy (Control of Noise From Commerce Industry and Trade). The noise measurements were performed at two residential sites:

1) No. 30 Church Rd Hazelwood.
2) No. 46 McLean St. Morwell.

These locations were selected because it was felt that they would provide a better representation of the typical ambient noise levels in the general area as well as being possible locations at which an impact might occur due to the operation of the power station.

3.1.1. No. 30 Church Road, Hazelwood

No. 30 Church Rd is located approximately 2.5 kilometres South- East from the proposed power station site, in a rural environment. There is a large timber mill located approximately 450 metres North –West from the residential property. The noise at this location due to the timber mill contributes to the background noise level at this location.

3.1.2. No. 46 McLean Street, Morwell.

No.46 McLean Street is located approximately 1.3 kilometres from the proposed power station site, in the residential area of Morwell.

Figure 3-1 below shows the locations of the two noise measurement locations.

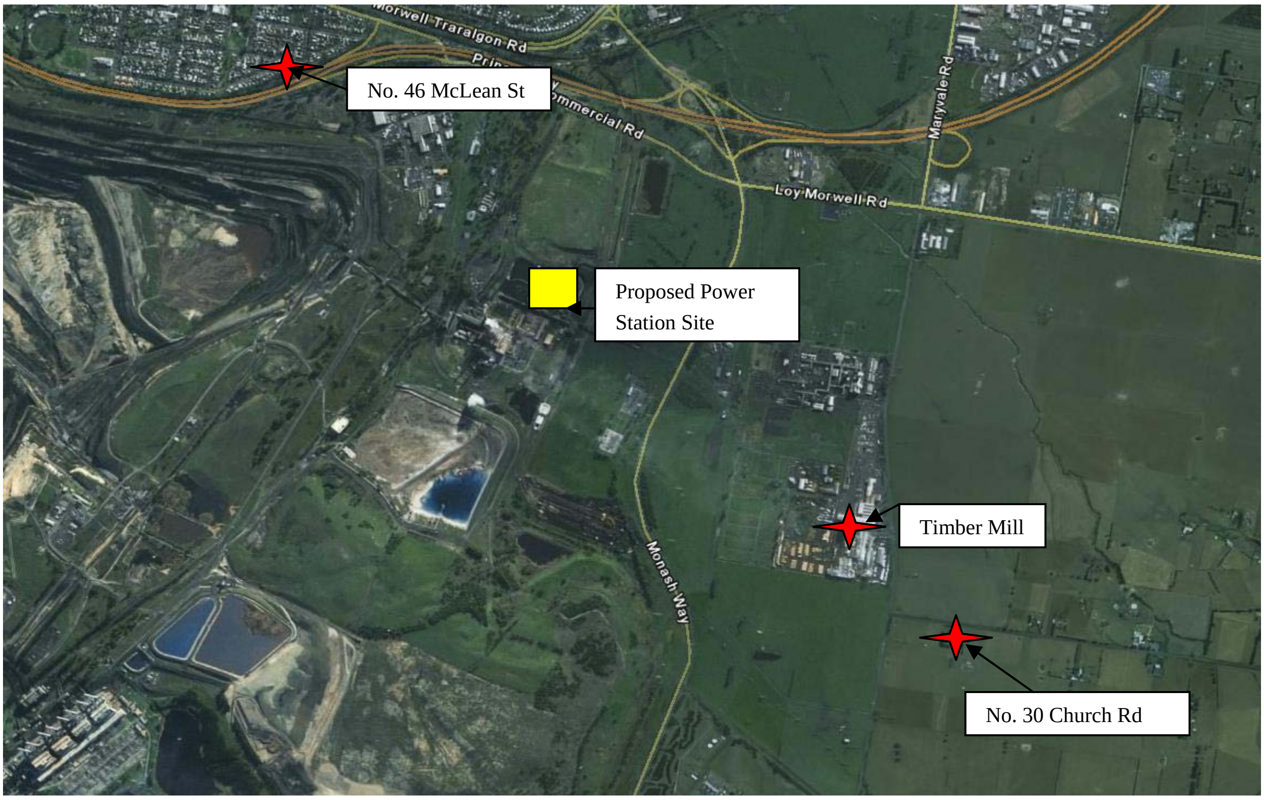

Figure 3-1 Environmental Noise Measurement Locations

3.2. Noise Limit Criteria

As the Victorian EPA has no set noise Policy/Regualtions or current Guidelines for noise from industry in rural Victoria, the Noise Limits were determined in accordance with the EPA Guideline "NOISE FROM INDUSTRY IN REGIONAL VICTORIA"- "Recommended Maximum Noise Levels From Commerce, Industry and Trade Premises in Regional Victoria-Draft For Consultation" Publication 1316, December, 2009 (NIRV). Although this guideline has not been adopted by the EPA as of yet, the criteria presented in this document have been based on the application of the NIRV. The predicted noise levels were then assessed against the Noise Limits of the power station at the nearest residential area.

The background noise measurements taken by SKM were used to adjust the "recommended maximum noise level" (RMNL) in accordance with steps 3, 4 and step 5 of the NIRV guideline.

In determining the RMNL at the nearest noise sensitive receiver location, the EPA Noise Guideline takes into consideration the land-use zoning of both the noise generating premises and the noise sensitive receivers.

Background noise levels in the noise sensitive area may also result in the RMNL being reduced if they are significantly lower than the calculated zone level.

Figure 3-2 below presents the land zoning around the proposed power station site as provided by the Government.

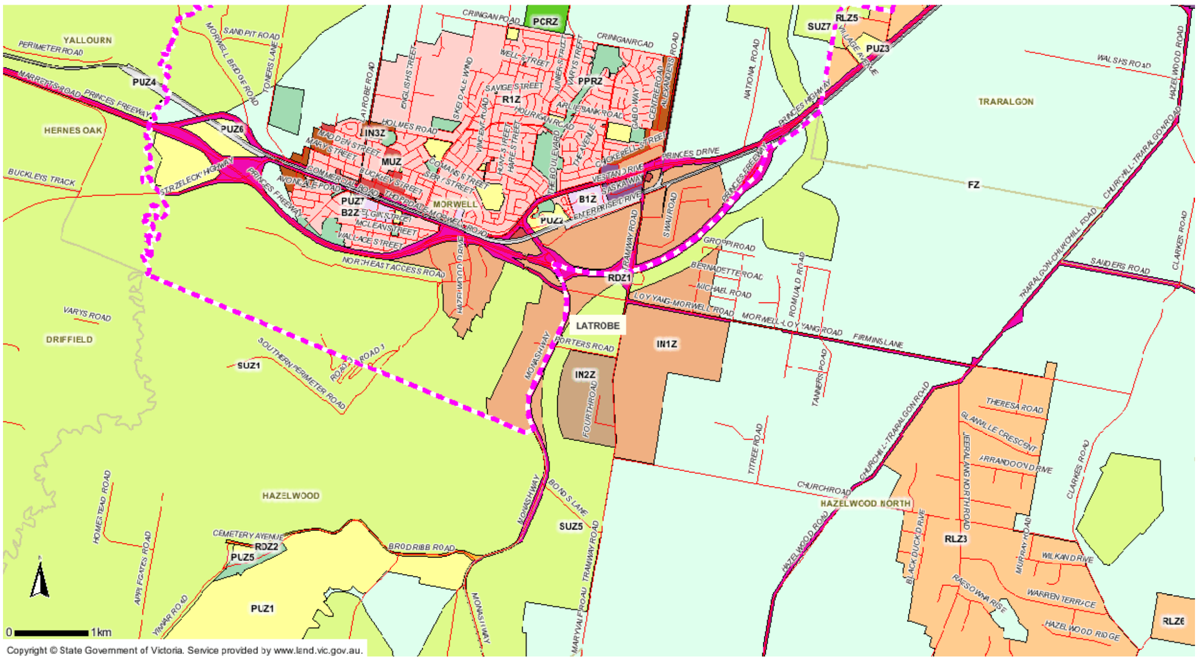

Figure 3-2 Zoning Plan Around the Proposed Power Station Site

3.3. Computer Prediction Modelling

The predicted noise levels at the nearest identified sensitive residences were determined using the SoundPLAN 7.0 computer modelling software. This modelling package is accepted and endorsed by numerous agencies nationally and internationally.

The SoundPLAN modelling was performed using the CONCAWE industrial noise prediction method. The CONCAWE method was selected because it is a noise prediction method that includes the influences of wind and atmospheric stability in a way which can be easily quantified with site meteorological data. The CONCAWE Method was originally published as "*The Propagation of Noise from Petroleum and Petrochemical Complexes to Neighbouring Communities*" by CONCAWE in 1981. This method has been tested and validated over distances of 100 – 2000 metres, under a range of meteorological conditions for noise emissions from large petrochemical and other plants.

Modelling the propagation of noise using SoundPlan allows for the following specific terms in the algorithms that determine the overall environmental sound propagation:

- Geometrical divergence
- Atmospheric absorption
- Source directivity
- Ground effects
- Reflection from surfaces
- Screening by obstacles (i.e. Power station plant shielding noise propagation from adjacent plant).
- Meteorological effects.

The ‘worst case’ propagation conditions were:

- 3m/sec wind from noise to noise sensitive receiver
- Pasquill stability class F
- Temperature 15^{o} C
- Humidity 50%

The SoundPlan computer model has a prediction uncertainty in the order of +/- 3dBA.

The noise model was developed using terrain contours at 10 m intervals and aerial photography to identify the locations of sensitive receivers (confirmed during the site inspection).

Meteorological conditions are modelled as three situations: Neutral, Worst Case and Prevailing Wind. Neutral indicates no wind and Pasquill stability class D. Worst Case indicates Pasquill stability class F, with a wind speed of 3 m/s in a direction from the noise source to the noise sensitive receivers in all directions. Prevailing Wind indicates a Pasquill stability class D with a wind speed of 3 m/s in the direction that is most prevalent for the proposed location of the IDGCC Plant (see Table 3-1 below).

Table 3-1 Weather Conditions Used in the Modelling

Neutral	**Pasquill Stability Class: D** **Temperature: 20 deg C** **Wind speed: 0 m/s**
Worst Case	Pasquill Stability Class: F Temperature: 15 deg C Wind speed: 3 m/s (Source to receiver)
Prevailing Wind	Pasquill Stability Class: D Temperature: 20 deg C Wind speed: 3 m/s (Westerly)

Figure 3-3 below shows the long term average wind rose for the Latrobe Valley Airport which is approximately 11 km to the north-west and is considered to be indicative of the typical wind conditions in the area surrounding the proposed IDGCC Power Station. The Prevailing Wind condition was modelled as a 3 m/s westerly wind.

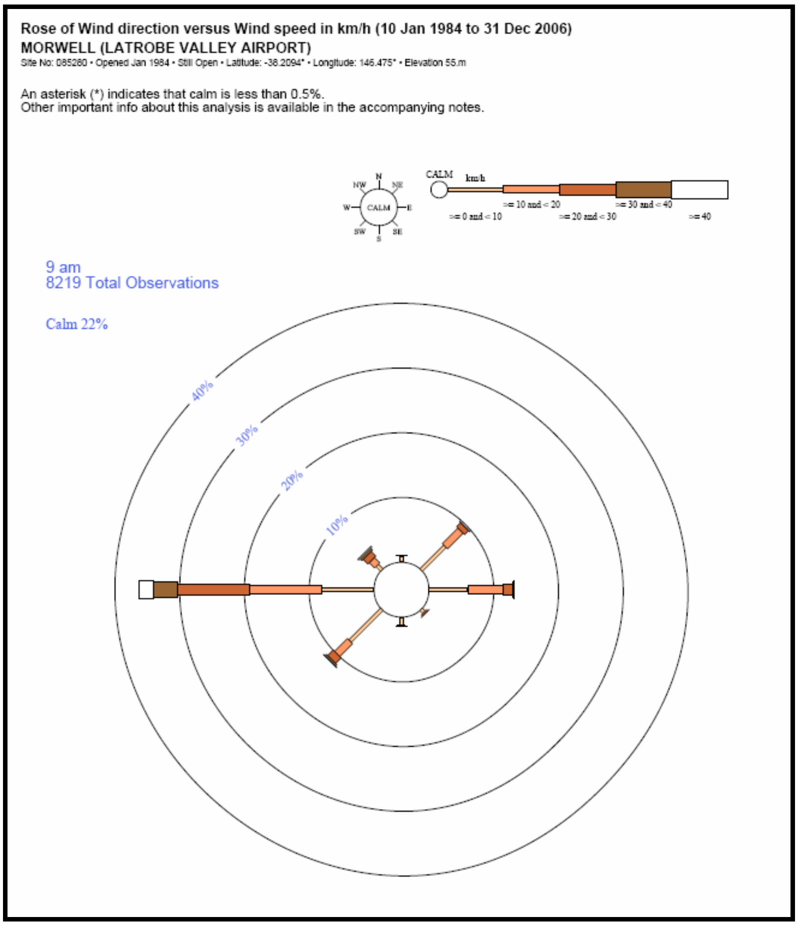

Figure 3-3 Latrobe Valley Wind Rose

4. Instrumentation

4.1. Unattended Background Noise Level Monitoring

The unattended noise level monitoring was performed using Bruel & Kjaer 2238 Mediator Integrating Sound Level Meters calibrated in a NATA accredited laboratory. These units are Type 1 data loggers.

The sound level meters were programmed to measure and store noise data continuously over one-hour sampling periods for the entire duration of the monitoring at each location (for a minimum of 7 days).

Statistical software calculates and stores the Ln percentile noise levels for each one hour sampling period over the measurement survey.

The data loggers were checked for calibration before and after the logging period.

5. Power Station Equipment Noise Data

5.1. Noise Level Prediction Modelling

The available sound power level data for the various components of the plant was very limited due to the inability of the manufacturers to supply the noise data information and also due to the highly confidential nature of the gasification process.

The sound power level data applied to various pieces of equipment have therefore been derived from an equipment data bank and from noise data of equipment of a similar configuration used for other power station projects.

5.1.1. CCGT Gas Turbine Model

As the final design configuration of the proposed combined cycled gas turbine has not been finalised, the gas turbine noise model was based on sound power level data for a Mitsubishi 210MW combined cycle gas turbine (CCGT) package that was used on a previous project.

The Mitsubishi data was scaled up by 1dB to model the 275MW CCGT units proposed to be used for this project[1]. The Mitsubishi units were a closed cycle system with heat-recovery steam generators and a steam turbine and also included all ancillary equipment such as:

- Lube oil/cooling oil systems
- Ventilation fans
- Steam Turbine
- Condenser Water Box
- Pumps (chemical feed/transfer, condensate extraction, condensate vacuum, CW booster)
- Air Compressor
- Grand Steam Condenser.

[1] The CCGT turbines to be used in the in the proposed project are 275 MW units and the only readily available Sound Power Level data for a CCGT of similar size is for a 210 MW Mitsubishi unit. To take into account the larger size of the CCGT units for the project, the corresponding noise data for the Mitsubishi unit has been scaled up using a scaling factor of $10\log_{10}(N_1/N_2)$.

5.1.2. Coal Gasifier Model

Due to the highly confidential design of the coal gassifier system equipment, the general equipment used in the plant has generally been modelled as blocks using noise data provided by HRL. As a result, any possible noise barrier effects may not have been modelled accurately.

The coal gasifier was modelled as three main blocks of equipment:

- Gasification Island
- Char Boiler
- Nitrogen Plant

Note, that due to the limited detail available regarding the location, sizes, heights and layout of the equipment associated with the coal gasification, the noise modelling results presented in this assessment are likely to be an over-estimation of the predicted noise levels expected from the final plant design. This is because items modelled as 'blocks' are not going to benefit from shielding effects likely to be present in the realistic final design of the plant. Thus, the presented noise level predictions might over estimate the actual noise emissions.

5.2. Noise Source Sound Power Levels

The Sound Power Level (PWL) of the gas turbine units and associated equipment was therefore determined from a combination of on-site measurements, data supplied by the original equipment manufacturers and data supplied by HRL.

The following PWLs were used in the SoundPLAN computer modelling.

5.3. Combined Cycle Gas Turbine (CCGT) – Heat Recovery Steam Generator (HRSG)

The PWL spectrum of one 275 MW CCGT is presented in ***Table 5-1*** below.

Table 5-1 275 MW CCGT PWL Spectrum

Configuration	Sound Power Level (dBA)									
	Octave Band Centre Frequency (Hz)									
	31.5	63	125	250	500	1000	2000	4000	8000	Total
Gas turbine	77	86	94	98	103	106	105	101	91	110
GT LO/CO System	58	67	78	83	87	91	91	87	77	96
GT Air Inlet Filter	82	91	91	93	98	101	98	96	88	105
GT Air Inlet Duct	90	99	100	102	107	109	107	104	97	114
GT Generator	69	83	95	95	101	103	101	95	86	107
HRSG Inlet Duct	79	89	90	92	97	101	100	99	92	106
HRSG	80	90	90	92	98	101	101	100	92	106.5
HRSG Stack Breakout	94	103	103	104	107	106	93	88	79	112
HRSG Stack Exhaust	75	93	97	94	93	85	66	51	30	101

The height of the combined cycle power plant stacks is estimated to be approximately 80m, with the final height to be determined mainly by technical and air quality requirements.

5.4. Integrated Drying and Gasification Plants

An indicative Sound Power Level spectrum is shown in Table 5-2 below.

Table 5-2 Gasification Plant Island PWL Spectrum

Configuration	Sound Power Level (dBA)									
	Octave Band Centre Frequency (Hz)									
	31.5	63	125	250	500	1000	2000	4000	8000	Total
Gasifier Air Heater	57	70	79	85	87	87	85	82	77	93
Pre Dryer Heater (and 21 Kw Fans)	57	70	79	85	87	87	85	82	77	93
Gasifier Multi Stage Air Compressor	44	53	68	74	78	84	90	87	78	93
Motors Gasifier Multi Stage Air Compressor	44	59	71	79	84	87	89	85	76	93
Recirculation Gas Compressor	44	53	68	74	78	84	90	87	78	93
Motor Recirculation Gas Compressor	44	59	71	79	84	87	89	85	76	93
Rotary Blowers Pre Dryer Blower Casing	63	73	82	86	86	87	85	80	71	93
Char Crusher (bottom of Gasifier)	44	59	71	79	84	87	89	85	76	93
Motors Char Crusher	57	68	75	81	90	86	84	81	76	93
Motor Rotary Blowers	44	53	68	74	78	84	90	87	78	93

5.5. Char Boiler

An indicative Sound Power Level spectrum is shown in Table 5-3 below.

Table 5-3 Char Boiler Equipment PWL Spectrum

Configuration	Sound Power Level (dBA)									
	Octave Band Centre Frequency (Hz)									
	31.5	**63**	**125**	**250**	**500**	**1000**	**2000**	**4000**	**8000**	Total
Char Boiler Package	65	78.5	87.5	92.5	95.5	95.5	93.4	90.5	85.5	101
Mill (Upstream of Char Boiler)	69.5	81	88	94	103	99	97	94	89	106
Motors Char Mill	54.5	70	82	89	95	98	99	96	87	103.5
FD Fans	52	65	74	80	82	82	80	77	72	88
ID Fans	52	65	74	80	82	82	80	77	72	88

5.6. Steam Turbines and Generators (STGs)

Table 5-4 below presents the typical Sound Power Level data used for the CCGT Steam Turbine Hall.

Table 5-4 Steam Turbines and Generators (STGs) PWL Spectrum

Configuration	Sound Power Level (dBA)									
	Octave Band Centre Frequency (Hz)									
	31.5	**63**	**125**	**250**	**500**	**1000**	**2000**	**4000**	**8000**	Total
Steam Turbine Hall	78	89	98	106	111	113	111	107	100	117
Steam Turbine in Colour Bond Enclosure	75	85	89	91	90	89	84	79	64	96.5

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5.7. Air Cooled Condensers

Table 5-5 below presents the typical Sound Power Level data used for the Air Cooled Condensers.

Table 5-5 Air Cooled Condensers PWL Spectrum

Configuration	Sound Power Level (dBA)									
	Octave Band Centre Frequency (Hz)									
	31.5	63	125	250	500	1000	2000	4000	8000	Total
Air Cooled Condensers	83	96	105	109	113	115	114	111	104	120

5.8. Nitrogen Plant

Table 5-6 below presents the typical Sound Power Level data used for the Nitrogen Plant equipment.

Table 5-6 Nitrogen Plant Equipment PWL Spectrum

Configuration	Sound Power Level (dBA)									
	Octave Band Centre Frequency (Hz)									
	31.5	63	125	250	500	1000	2000	4000	8000	Total
Nitrogen Plant Air Compressor	48	57	72	79	82	88	95	91	82	97
Motor Nitrogen Plant Air Compressor	49	64	76	84	89	93	94	91	81	98
Air Separation Unit & Auxiliaries	66	81	89	89	90	91	94	92	87	99
Motor Nitrogen Compressor	48	57	72	79	82	88	94	91	82	97
Nitrogen Compressor	49	64	76	84	89	93	94	91	81	98

5.9. Sundry Equipment

Table 5-7 below presents the typical PWL data used for the sundry plant equipment.

Table 5-7 PWL data for sundry plant equipment

Configuration	Sound Power Level (dBA)									
	Octave Band Centre Frequency (Hz)									
	31.5	63	125	250	500	1000	2000	4000	8000	Total
ST Main Transformer	61	77	88	92	89	77	66	62	61	94.5
HP / LP Recirculating Pumps	55	59	73	82	86	82	90	83	70	93
Station Transfer Conveyor SWL per metre	32	48	59	67	78	79	74	67	61	82.5
Station Drivehead Transfer Conveyor	49.5	65	76	91	100	104	101	94	82	107
Station Shuttle Conveyor SWL per metre	32	48	59	67	78	79	74	67	61	82.5
Station Drive Head Shuttle Conveyor	49.5	65	76	91	100	104	101	94	82	107
Station Rising Conveyor SWL per metre	32	48	59	67	78	79	74	67	6	82.5
Station Drivehead Rising Conveyor	49.5	65	76	91	100	104	101	94	82	107
Station Ground Flare Max Continuous (100tonne/hour)	63	73	78	84	90	95	97	94	89	101.5

6. Results

6.1. Environmental Background Noise Level Survey

The two measurement sites were selected due to these properties being the closest to the proposed power station and most likely to be impacted by it.

6.1.1. No.30 Church Road, Hazelwood

Figure 6-1 below presents the L_{A90} and L_{Aeq} sound pressure levels measured at No.30 Church Rd. Hazelwood between the 15th and 22nd of October, 2009.

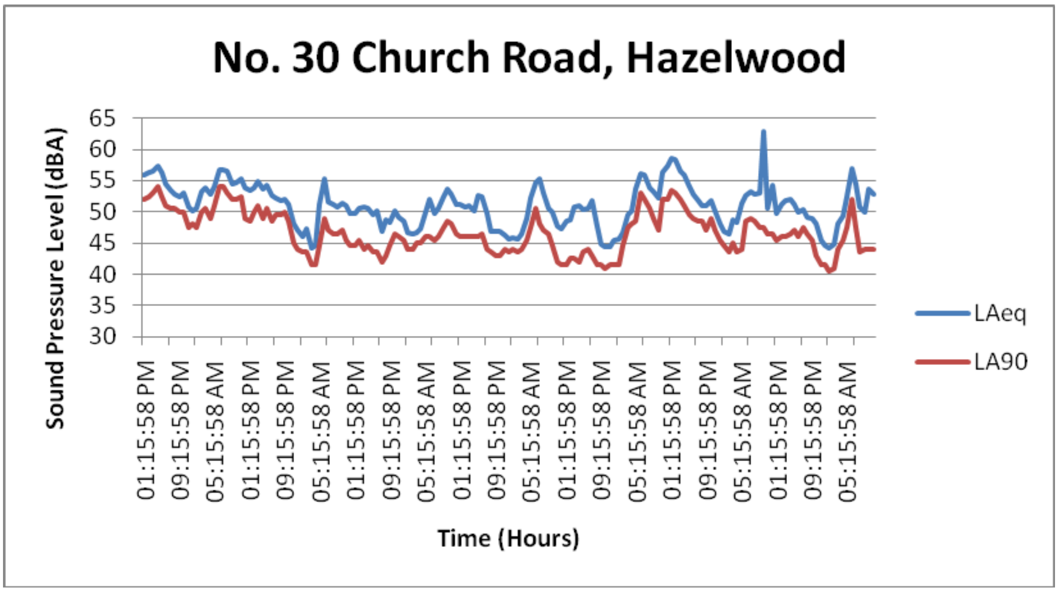

Figure 6-1 Sound Pressure Level versus Time Trace

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Table 6–1 below presents the calculated average daily noise levels using the day, evening and night time periods as defined in the EPA SEPP Noise Policy No. N-1.

Table 6-1 Average Background Sound Pressure Levels (dBA) for the Day, Evening and Night Time Periods

Date	Time Period (hours)		
	Day	Evening	Night
	0700 - 1800	1800 - 2200	2200 - 0700
15/10/2009	52.5*	50.3	50.2
16/10/2009	50.5	49.4	44.4
17/10/2009	45.0	44.0	45.2
18/10/2009	46.6	43.4	45.6
19/10/2009	43.4	41.8	46.4
20/10/2009	50.8	48.3	45.6
21/10/2009	46.7	45.6	44.6
22/10/2009	43.9*		
Minimum:	**43.5**	**42**	**44.5**

***Incomplete Noise Measurement**

Discussions with the residents at this location and assessment of the data in Table 6-1 above lead to the conclusion that the background noise levels at this location are impacted by works at the Carter Holt Harvey Timber Mill located approximately 500 metres to the north West of the residential building.

6.1.2. No.46 McLean Street, Morwell

Figure 6-2 below presents the hourly L_{A90} sound pressure levels measured at No.46 McLean St. Morwell between the 15th and 22nd of October, 2009.

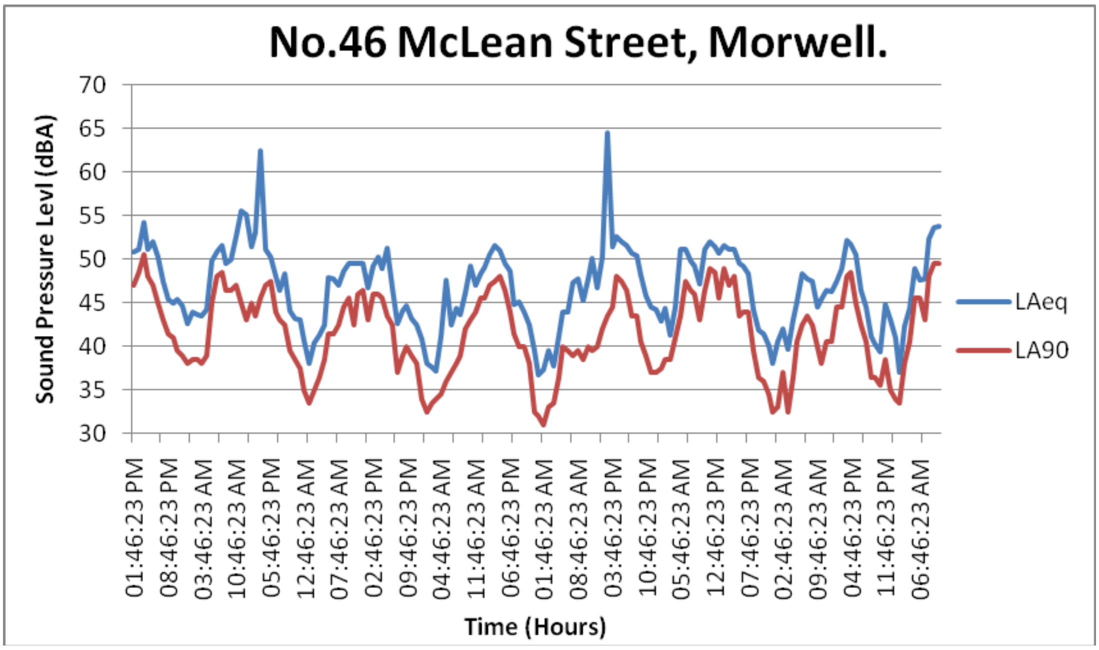

Figure 6-2 Sound Pressure Level versus Time Trace

Table 6–2 below presents the calculated average daily noise levels using the day, evening and night time periods as defined in he EPA SEPP Noise Policy No. N-1.

The residential property in which the background noise survey at Mc Lean St was performed is approximately 210 metres from the Princes Freeway. This property is not the closest property to the proposed power station site or to the Princes Freeway. The closest property to both the Princes Freeway and the proposed power station site is approximately 50 metres closer.

An ‘on site’ subjective assessment was made at this measurement site and it was deemed that the background noise levels at this location were significantly dominated by road traffic noise and that industry noise was not discernable.

Table 6-2 Average Background Sound Pressure Levels (dBA) for the Day, Evening and Night

Date	Time Period (hours)		
	Day	Evening	Night
	0700 - 1800	1800 - 2200	2200 - 0700
15/10/2009	48.2*	42.6	40.8
16/10/2009	45.9	42.3	37.5
17/10/2009	44.7	39.6	35.4
18/10/2009	44.2	41.4	35.1
19/10/2009	42.0	43.5	39.9
20/10/2009	46.6	41.0	36.1
21/10/2009	43.2	39.0	38.4
22/10/2009	47.5*		
Minimum:	**42**	**39**	**35**

**Incomplete Noise Measurement*

6.2. Derived RMNL's

The RMNL's were determined in accordance with the NIRV. From the relevant land use zoning map, the generating zone is Special Use Zone (SU1) and the two receiver zones where the background noise levels were measured are zoned Farming (FZ) and Residential (RZ1).

Figure 7-1 presents a plan of the land zoning for the power station site and the location of the noise sensitive receiver locations.

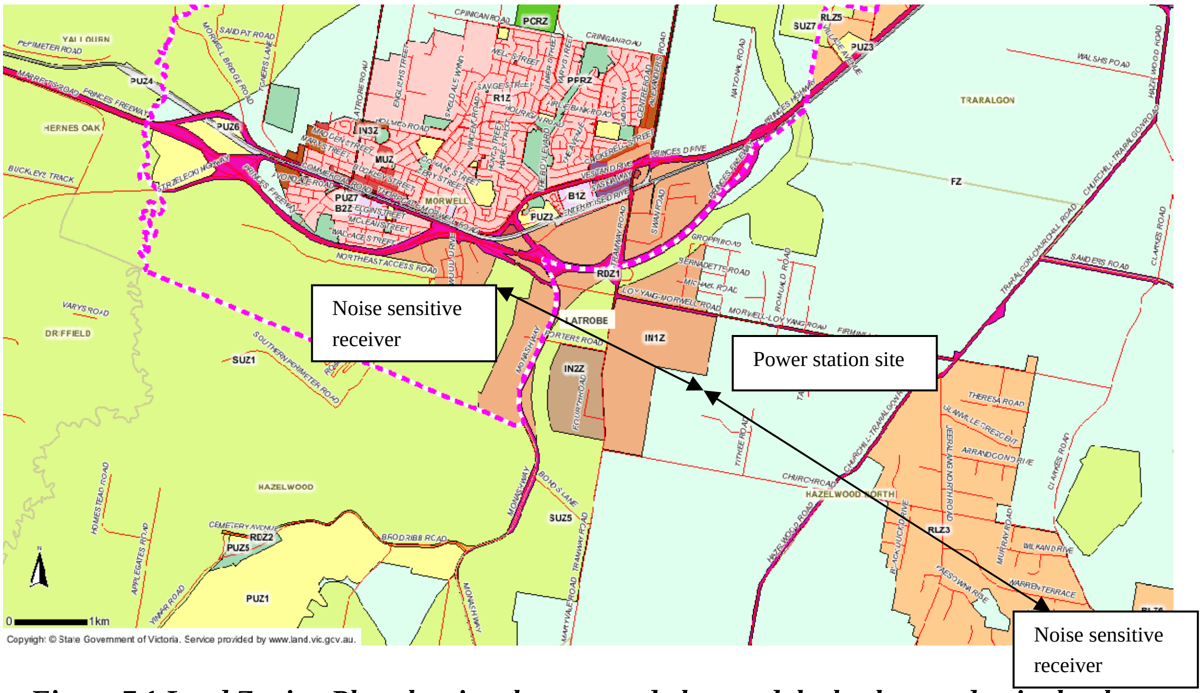

Figure 7.1 Land Zoning Plan showing the proposed plant and the background noise level measurement locations

The zone level can therefore be determined using Table 1 of the Zoning Levels in the Guideline Publication 1316, as excerpted below.

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Table 1: Zone Levels

Planning zone for noise-receiving location

Planning zone for noise-generating use: Generating Zone ↓ / Receiving zone →	❑ Green Wedge A GWAZ ❑ Rural Conservation RCZ ❑ Rural Living RLZ	❑ Low Density Residential LDRZ ❑ Public Conservation and Resource PCRZ ❑ Public Park and Recreation PPRZ ❑ Public Use 2,5 PUZ ❑ Urban Floodway UFZ	❑ Farming FZ† ❑ Green Wedge GWZ ❑ Residential 1 R1Z ❑ Residential 2 R2Z ❑ Residential 3 R3Z ❑ Rural Activity RAZ ❑ Township TZ ❑ Urban Growth UGZ‡	❑ Business 1 B1Z ❑ Business 2 B2Z ❑ Business 5 B5Z ❑ Comprehensive Development CDZ‡ ❑ Mixed Use MUZ ❑ Priority Development PDZ‡ ❑ Public Use 1,3,4,6,7 PUZ ❑ Road RDZ	❑ Industrial 3 IN3Z ❑ Special Use SUZ‡	❑ Business 3 B3Z ❑ Business 4 B4Z	❑ Industrial 1 IN1Z ❑ Industrial 2 IN2Z
▸ Low Density Residential LDRZ ▸ Public Conservation and Resource PCRZ ▸ Public Park and Recreation PPRZ ▸ Residential 1 R1Z ▸ Residential 2 R2Z ▸ Residential 3 R3Z ▸ Urban Floodway UFZ	Day: 45 Evening: 37 Night: 32	Day: 45 Evening: 39 Night: 34	Day: 45 Evening: 40 Night: 35	Day: 47 Evening: 42 Night: 37	Day: 48 Evening: 43 Night: 38	Day: 50 Evening: 45 Night: 40	Day: 53 Evening: 48 Night: 43
▸ Business 5 B5Z ▸ Farming FZ† ▸ Green Wedge GWZ ▸ Green Wedge A GWAZ ▸ Public Use 2,5 PUZ ▸ Rural Activity RAZ ▸ Rural Conservation RCZ ▸ Rural Living RLZ ▸ Urban Growth UGZ‡	Day: 45 Evening: 38 Night: 33	Day: 45 Evening: 40 Night: 35	Day: 46 Evening: 41 Night: 36	Day: 48 Evening: 43 Night: 38	Day: 50 Evening: 45 Night: 40	Day: 52 Evening: 47 Night: 42	Day: 54 Evening: 49 Night: 44
▸ Business 1 B1Z ▸ Business 2 B2Z ▸ Comprehensive Development CDZ‡ ▸ Mixed Use MUZ ▸ Priority Development PDZ‡ ▸ Public Use 1,3,4,6,7 PUZ ▸ Road RDZ ▸ Township TZ	Day: 45 Evening: 40 Night: 35	Day: 47 Evening: 42 Night: 37	Day: 48 Evening: 43 Night: 38	Day: 50 Evening: 45 Night: 40	Day: 52 Evening: 47 Night: 42	Day: 53 Evening: 48 Night: 43	Day: 55 Evening: 50 Night: 45
▸ Industrial 3 IN3Z ▸ Special Use SUZ‡	Day: 46 Evening: 41 Night: 36	Day: 49 Evening: 44 Night: 39	Day: 50 Evening: 45 Night: 40	Day: 52 Evening: 47 Night: 42	Day: 53 Evening: 48 Night: 43	Day: 55 Evening: 50 Night: 45	Day: 56 Evening: 51 Night: 46
▸ Business 3 B3Z ▸ Business 4 B4Z	Day: 48 Evening: 43 Night: 38	Day: 50 Evening: 45 Night: 40	Day: 52 Evening: 47 Night: 42	Day: 54 Evening: 49 Night: 44	Day: 55 Evening: 50 Night: 45	Day: 56 Evening: 51 Night: 46	Day: 57 Evening: 52 Night: 47
▸ Industrial 1 IN1Z ▸ Industrial 2 IN2Z	Day: 50 Evening: 45 Night: 40	Day: 52 Evening: 47 Night: 42	Day: 53 Evening: 48 Night: 43	Day: 55 Evening: 50 Night: 45	Day: 56 Evening: 51 Night: 46	Day: 57 Evening: 52 Night: 47	Day: 58 Evening: 53 Night: 48

† In the Farming Zone, where the subject agricultural activity is 'Intensive', then an adjustment of +3 dB should be applied to the determined Zone Levels to reflect amenity expectations of locally intense farming activities. Intensive farming activities are agricultural activities under the planning scheme (Clause 74), including horticulture and timber production, but not:

- 'extensive animal husbandry'
- 'apiculture'
- other 'crop raising'.

‡ For Special Use, Comprehensive Development and Priority Development, and Urban Growth zones, see notes in facing page.

Note: The public use zones include (1, 3, 4, 6, 7) Service & Utility, Health & Community, Transport, Local Government, Other Public Use; (2, 5) Education, Cemetery/Crematorium.

The RMNL's were then derived by following the procedure in Section 3 of the NIRV.

6.2.1. No.30 Church Road, Hazelwood

Table 6-3 below shows the derivation of the RMNL's for No.30 Church Road, Hazelwood.

Table 6-3 Calculated RMNL's at No. 30 Church Rd, Hazelwood.

Noise Level Criteria dBA			
Time Period:	Day 0700 - 1800	Evening 1800-2200	Night 2200-0700
Zone Level – Table 1 (NIRV Publication 1316) **Generating Zone – Special Use SUZ#** **Receiver Zone – Farming FZ**	50	45	40
Adjustment according to step 3 (distance from emitter zone to noise sensitive receiver 2,500m)*	-9	-9	-9
Calculated Adjusted Zone Level	41	36	31
Minimum as set out in Step 4 of publication 1316	*45*	*37*	*32*
Measured Minimum Period Average Background Noise Level	43.5	42	44.5
Background Noise level + adjustment [according to step 5] #	43.5+10 = 53.5	42+5 = 47	44.5+5 = 49.5
Greater of the adjusted Zone Level and the Background Noise Level plus adjustment in accordance twith step 5	53.5	47	49.5
Recommended Maximum Noise Level	**53.5**	**47**	**49.5**

**** Further than 900 metres from the industrial premises' zone boundary, maximum subtraction 9 dB***

 # Within 600 metres of a divided main road and 1000 metres from a Freeway

It must be noted that the noise levels generated by the timber mill located approximately 420 metres to the north - west of the environmental measurement site had an impact on the measured background noise levels at this location. Therefore the derived RMNL's at this location, as derived above, are higher than would be the case for a true background noise level unaffected by the timber mill noise.

6.2.2. No. 46 McLean Street, Morwell.

Table 6-4 shows the derivation of the MRNL's for the residential area at No. 46 McLean Street, Morwell.

Table 6-4 Calculated Noise Level Limits for No.46 McLean St., Morwell.

Noise Level Criteria dBA			
Time Period:	Day 0700 - 1800	Evening 1800-2200	Night 2200-0700
Zone Level– Table 1 (NIRV Publication 1316) **Generating Zone – Special Use SUZ** **Receiver Zone – Residential 1Z**	50	45	40
Adjustment according to step 3 **(distance from emitter zone to noise sensitive receiver 1,300 m)***	-9	-9	-9
Adjusted Zone Level	41	36	31
Minimum as set out in Step 4 of publication 1316	*45*	*37*	*32*
Measured Minimum Period Average Background Noise Level	42	39	35
Measured Background Noise Level + adjustment [according to Step 5] #	42+10 = 52	39+5 = 44	35+5 = 40
Greater of the adjusted Zone Level and the Background Noise Level plus adjustment in accordance to step 5	52	44	40
Recommended Maximum Noise Level	**52**	**44**	**40**
From step 6 titled 'Multiple Noise Contributors", if the land package is greater than 10 ha and expansion of the power station' is likely, then the Recommended Maximum Noise Level becomes the above criteria – 3 dB.**	**49**	**41**	**37**

**** Further than 900 metres from the industrial premises' zone boundary maximum subtraction 9 dB***

 # Within 600 metres of a divided main road and 1000 metres from a Freeway

***** Step 6 of the NIRV states' Where there are :***

- Industrial premises in an Industrial 1 or Industrial 2 zone with at least two other allotments in the same zoned piece of land

  or

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- Industrial premises on an allotment greater than 10ha in any zone where expansion is likely, industry is encouraged to design plant or operations so that their emissions are less than the recommended level.

  As a guide, the design target should be no greater than the recommended level minus 3 dB (for each period of the day). The practicality and the initial costs of noise control should be considered, as well as the practicality and costs for future noise control, in the event that noise from multiple sources was assessed as a major issue.

Note : The land package where the power station is to be constructed is greater than 10 ha but that no future expansion of the power station is likely in the foreseeable future. If that is the case, then for this scenario, the RMNL's at the Mclean St Residence would become:

- 52 dBA for Day
- 44 dBA for the Evening
- 40 dBA for the night time period

6.3. Noise Prediction Modelling

The predicted noise levels at the two identified residential receptors for the various weather conditions are shown below for the worst case, neutral and prevailing conditions. The resultant noise level contours are shown in Appendices A, B and C respectively.

Table 6-5 Predicted L_{Aeq} Noise Levels due to IDGCC Power Plant

Predicted Noise Level due to the Proposed IDGCC Plant at Nearby Sensitive Receptor Locations (dBA)		
Location	***30 Church Rd, Hazelwood***	***46 McLean St, Morwell***
Predicted Noise Level 'Worst' case	34.5	45.5
Predicted Noise Level 'Neutral' case	30.5	43
Predicted Noise Level 'Prevailing Wind' case	34.5	41

7. Discussion

7.1. Residential Building at No. 30 Church Rd.

The night time criterion is the critical noise level to be met by the IDGCC plant because the plant will be operating 24 hours per day 7 days aweek.

It can be seen that the predicted L_{Aeq} noise level at No.30 Church Road is only 34.5 dBA under worst case propagation conditions. This is well below the derived night time RMNL of 49.5 dBA at this location for all meteorological conditions. So even allowing for the somewhat elevated measured background noise level due to the timber mill, it is likely that compliance with the non-mill impacted derived RMNL would be achieved.

7.2. Residential Building at No. 46 McLean St.

The predicted noise level at No. 46 McLean Street for the ‘worse’ case scenario can be seen to exceed the night time RMNL at this location by the order of 5 dBA. This residential location is approximately 1.3 km away from the proposed plant.

Table 7-1 lists the main individual noise sources in terms of their noise level contribution for the ‘worst case’ scenario at No.46 McLean Street .

Table 7-1 ICCGT Plant Noise Source Ranking List at No. 46 McLean Street, Morwell.

Source Contribution Ranking		
Ranking	Plant Item Name	Predicted Noise Level (dBA)
1	ACC	40
2	HRSG Stack Breakout	40
3	GT Air Inlet Duct	36
4	GT Air Inlet Filter	35
5	GT Enclosure	32
6	Transformer	30.5
7	Nitrogen Plant	30
8	Station Conveyor	30
9	Generator	29.5
10	HRSG	28
11	HRSG Stack Exhaust	27

12	Char Boiler	27
13	GT Aux Transformer	24
14	Gasifier	21
	TOTAL PREDICTED SPL	45.5
15	Remaining Plant Equipment (approximately 50 noise sources)	27
	TOTAL PREDICTED SPL	45.5

Although the RMNL is predicted to be exceeded at this location, it is difficult to provide detailed noise mitigation recommendations until the final acoustic detail on the CCGT units and the ACC Unit is available.

We also note that the current noise level predictions are based on our best estimates for the various Sound Power Levels and that these need to be verified prior to any final decisions regarding noise mitigation.

The first four items on the ranking list may require some form of noise mitigation measures to be implemented in order to ensure compliance with the night time RMNL at this location.

7.2.1. Feasible Noise Mitigation Measures

Although the final design has not been completed, noise mitigation treatments could include:

- Stack Breakout & Exhaust– Attenuator fitted to the stack

  An attenuator could be fitted to the exhaust stack. The attenuator could reduce the emitted noise level by 15 dBA. Breakout noise could be reduced by the use of acoustic lagging and/or an enclosure and could likewise provide a noise level reduction of the order of 15 dBA.
- Air cooled condenser (ACC) – replacement of the cooling fan blades with a ‘low noise’ type. The original ACC design and prediction modelling was based on the ‘normal’ fan configuration fitted to the ACC units. A low noise fan blade has been developed by ACC manufacturers which can achieve a 7 dBA noise reduction and could be fitted to the ACC unit. The proposed ACC unit will have the proprietary ‘quiet’ fan blades fitted.
- Air Inlet Filter – upgrade of the inlet attenuator to achieve a minimum extra 10 dBA noise level reduction.
- Air Inlet Duct – The fitting of additional lagging (acoustic rather than thermal) to the inlet duct to achieve an additional 10 dBA noise level reduction.

- GT Main Transformer – Enclosure or acoustic barriers around transformer to achieve 10 dBA additional noise level reduction.
- Nitrogen Plant – enclosures to be fitted around various high noise level sources to achieve 10 dBA additional noise level reduction.
- Station Conveyor – enclosure fitted around conveyor drives to achieve 10 dBA additional noise level reduction.
- Char Boiler – Acoustic lagging around the char boiler unit to achieve 5 dBA additional noise level reduction.

Table 4 below demonstrates how the night period RMNL criterion can be met at No. 46 McLean Street with noise mitigation applied to the major noise sources.

- **Table 2 Possible Noise Mitigation Scenario**

Predicted Sound Pressure Level at 46 McLean Street After Noise Mitigation				
Ranking	**Source**	**Predicted SPL at Noise Sensitive Receiver (dBA)**	**Feasible Noise Mitigation Reduction (dBA)**	**Predicted SPL after Mitigation (dBA)**
1	ACC	40.2	7	33.2
2	HRSG Stack Breakout	40.0	15	30.0
3	GT Air Inlet Duct	35.9	15	25.9
4	GT Air Inlet Filter	34.7	10	22.7
5	GT Enclosure	32.0	-	32.0
6	GT Main Transformer	30.4	10	25.4
7	Nitrogen Plant	30.3	10	30.3
8	Station Conveyor	29.9	10	29.9
9	Generator	29.4	-	29.4
10	HRSG	28.2	-	28.2
11	HRSG Stack Exhaust	27.1	-	27.1
12	Char Boiler	26.8	5	26.8
13	GT Aux Transformer	23.9	-	23.9
14	Gasifier	21.1	-	21.1
15	Demineralisation	10.5	-	10.5

	Plant			
16	Syngas pumps	2.5	-	2.5
17	Sundry equipment	27	-	27
	Predicted Total dBA	**45.5**		**38**

To achieve any further noise reduction (down to 37 dBA if that is applicable), would likely require a very significant additional expenditure on noise mitigation than what is already proposed. As stated in the NIRV, the practicality and the initial costs of noise control should be considered, as well as the practicality and costs for future noise control, in the event that noise from multiple sources was assessed as a major issue.

7.3. Acoustic impact on Commercial Buildings

There are commercial buildings located approximately 500 metres to the North West of the of the proposed power station site.

These commercial properties are a book shop and a laboratory.

Using the predicted noise level contours, which do **not** take into account any possible noise mitigation (as described above) but use the original noise data supplied, it can be seen that the power station will generate a noise level of approximately 60 dBA at these sites.

With the noise mitigation, the predicted noise levels at these sites would be drop to approximately 53 dBA.

Given a minimum of 20 dBA noise reduction across a façade (windows closed), this would then equate to internal noise levels within the buildings of 40 dBA (worse case weather conditions – no noise mitigation) and 33 dBA (worse case weather conditions – with proposed noise mitigation).

Australian Standard AS/NZ 2107 – 2000 recommends Satisfactory and Maximum design L_{Aeq} Sound Pressure Levels for various areas of occupancy in buildings as follows:

- Laboratory - 40 dBA (Satisfactory)

  50 dBA (Maximum)

- Book Shop - 45 dBA (Satisfactory)

50 dBA (Maximum)

It can seen that the noise levels inside the commercial buildings will therefore be below the recommended noise levels as presented in AS/NZS 2107 -2000, even for the unmitigated plant noise emission.

8. Conclusion

Dual Gas Pty Ltd is proposing to develop a demonstration power station using IDGCC technology, which will generate approximately 600MW of power for sale in the National Electricity Market (NEM).

SKM was commissioned to determine the existing background noise levels and to also conduct computer modelling to predict the noise levels generated by the proposed gasification plant and power station at the nearest identified neighbouring residences.

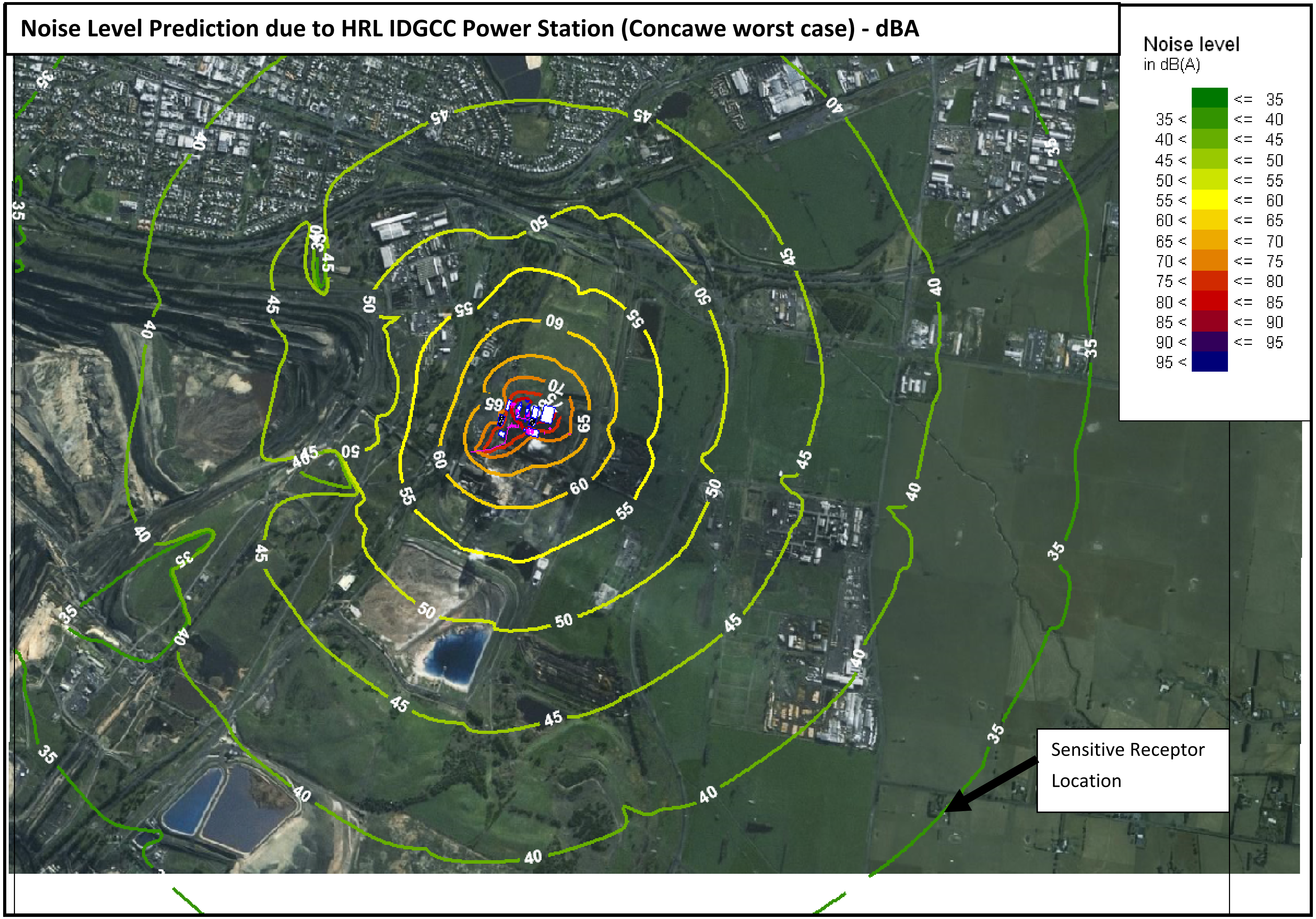
Recommended Maximum Noise Levels were developed based on the EPA Guideline "NOISE FROM INDUSTRY IN REGIONAL VICTORIA"- "Recommended Maximum Noise Levels From Commerce, Industry and Trade Premises in Regional Victoria- Draft For Consultation" Publication 1316, December, 2009".

The noise levels due to the plant are predicted to comply with the night time RMNL at No.30 Church. St, Hazelwood for the 'worst case', neutral and prevailing meteorological conditions even allowing for the elevated background noise levels at this location due to the timber mill.

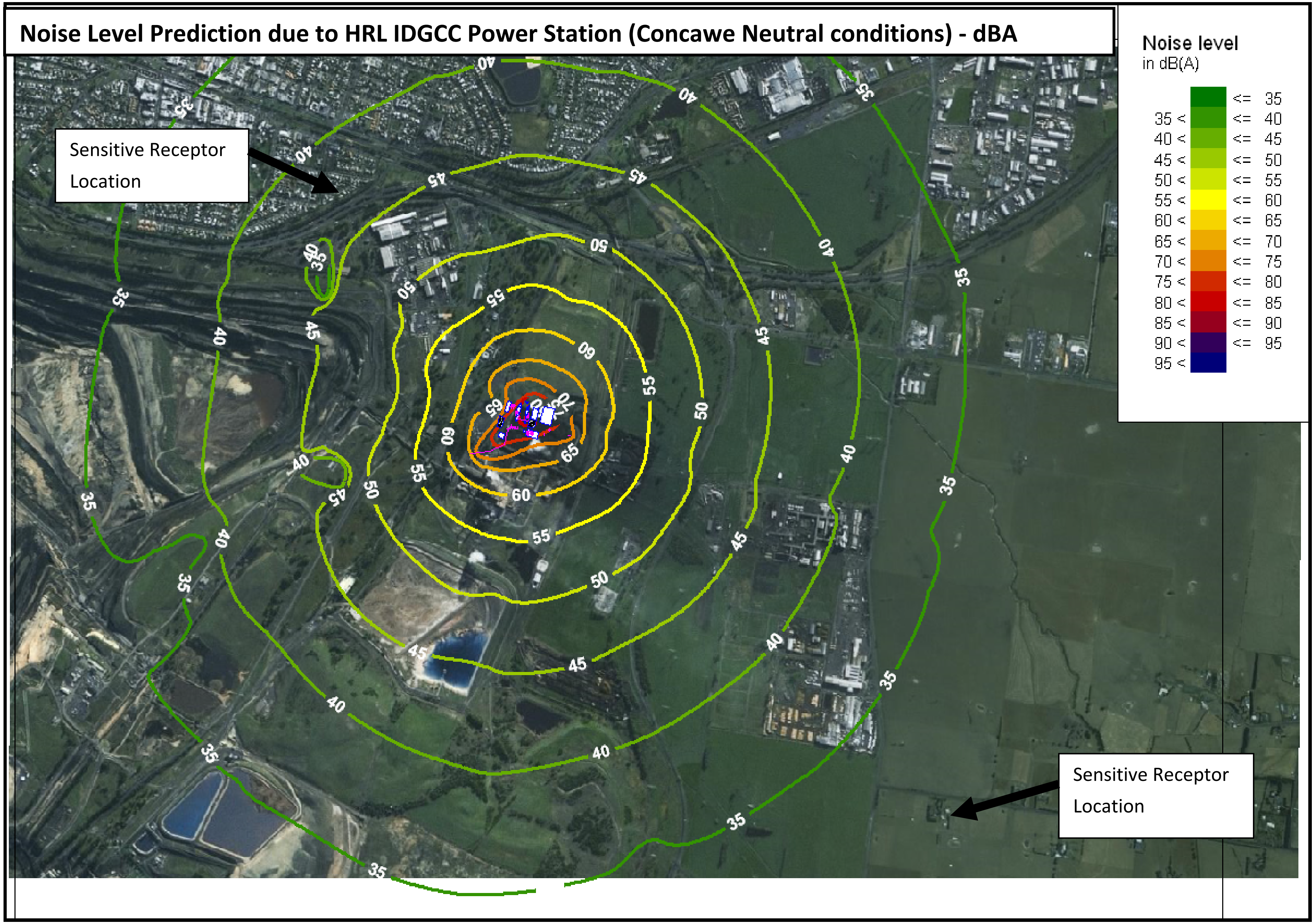
However, the noise level prediction results indicate that the night time RMNL will be exceeded by of the order of 5 dBA for the 'worse case' meteorological conditions at No. 46 McLean Road, Morwell.

Based on the results obtained, noise mitigation will be required to ensure compliance with the EPA noise limit criteria. However, we note that the results obtained are based on our best estimates of the Sound Power Levels for the CCGT units and ACC unit. Confirmation of noise modelling data will be required prior to any decision as to the degree of noise mitigation measures required.

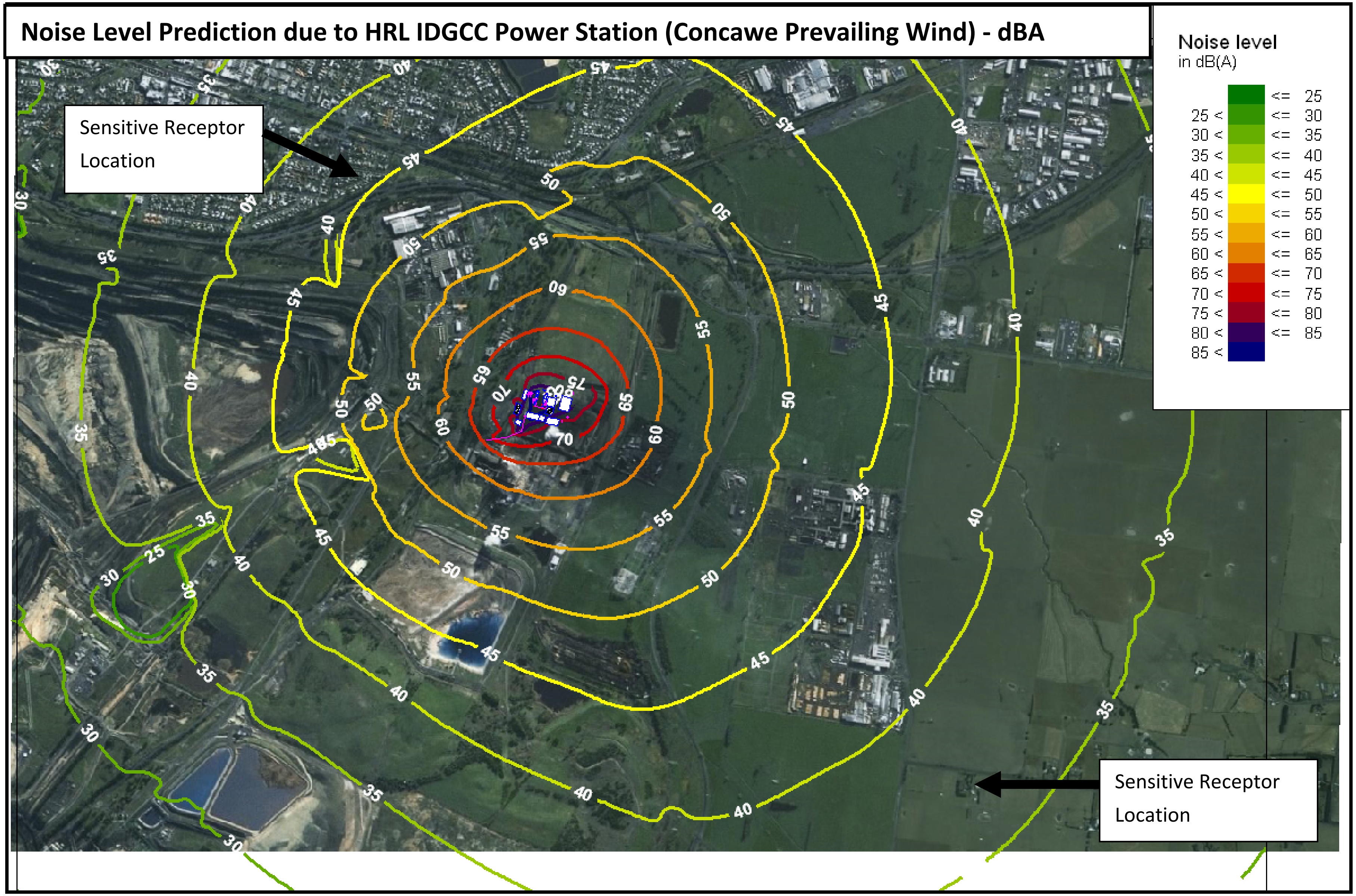
Appendix A Noise Contour Plot – Worst Case Weather


Noise Level Prediction due to HRL IDGCC Power Station (Concawe worst case) - dBA
Noise level
in dB(A)
<= 35
35 < <= 40
40 < <= 45
45 < <= 50
50 < <= 55
55 < <= 60
60 < <= 65
65 < <= 70
70 < <= 75
75 < <= 80
80 < <= 85
85 < <= 90
90 < <= 95
95 <
Sensitive Receptor Location
35
40
45
50
55
60
65
70

Appendix B Noise Contour Plot – Neutral Weather


Noise Level Prediction due to HRL IDGCC Power Station (Concawe Neutral conditions) - dBA
Noise level
in dB(A)
<= 35
35 < <= 40
40 < <= 45
45 < <= 50
50 < <= 55
55 < <= 60
60 < <= 65
65 < <= 70
70 < <= 75
75 < <= 80
80 < <= 85
85 < <= 90
90 < <= 95
95 <
Sensitive Receptor Location
Sensitive Receptor Location
35
40
45
50
55
60
65
70

Appendix C Noise Contour Plot – Prevailing Wind Weather Conditions


Noise Level Prediction due to HRL IDGCC Power Station (Concawe Prevailing Wind) - dBA
Sensitive Receptor Location
Sensitive Receptor Location
Noise level
in dB(A)
<= 25
25 < <= 30
30 < <= 35
35 < <= 40
40 < <= 45
45 < <= 50
50 < <= 55
55 < <= 60
60 < <= 65
65 < <= 70
70 < <= 75
75 < <= 80
80 < <= 85
85 <

Appendix F   Class 3 Air Pollutants Assessment

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ASSESSMENT FOR THE POTENTIAL OF CLASS 3 AIR POLLUTANTS FROM THE 600 MW DUAL GAS DEMONSTRATION PROJECT

Report No: HLC/2010/057
June 2010
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by
Glenn Innes, Chris Black and Waven Zhang

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SUMMARY

Under the State Environment Protection Policy (SEPP) for Air Quality Management particular importance is placed on Class 3 Indicators, which are defined as extremely hazardous substances. For these compounds Maximum Design Criteria ground level concentrations (GLCs) are specified. HRL Developments (HRLD) has requested that HRL Technology (HRLT) review the potential for Class 3 Indicators being emitted from the 600 MW Dual Gas Demonstration Project (DGDP).

In order to make estimates of the resulting Class 3 pollutants emitted from the proposed 600 MW DGDP several assumptions and approximations had to be made. Typically, power generators and industrial facilities rely on using emission factors to estimate stack emissions since they do not generally perform stack sampling for Class 3 Indicators. Rather, for electricity generators emissions of Class 3 Indicators are typically determined using the National Pollutant Inventory (NPI) emission factors for Fossil Fuel Electric Power Generation. However, NPI emission factors are not available for all of the Class 3 Indicators specified in the SEPP and not all of the Class 3 Indicators are listed as NPI reportable pollutants.

In order to obtain a better understanding of the potential for Class 3 emissions from the DGDP a brief literature review was conducted regarding the emissions of Class 3 pollutants from gasification plant. It was found that there is not a significant amount of publically available information from national or international studies of emissions from integrated gasification combined cycle plant that measured Class 3 Indicators.

The general finding of most studies reviewed is that coal fuel gasification power systems typically achieved the lowest levels of criteria pollutant air emissions (NOx, SOx, CO, PM10) of any coal-fired power plants in the world. Additionally, it was found that emissions of trace hazardous air pollutants are extremely low, comparable with those from direct-fired combustion plants that use advanced emission control technologies.

HRLT previously conducted air dispersion modelling of Class 3 Indicators from the existing power stations and paper mills in the Latrobe Valley. The ground level concentrations (GLCs) predicted from the air dispersion modelling were compared with the SEPP Design Criteria and it was found that all were below the Design Criteria and were typically significantly below the Design Criteria GLCs.

Ballpark estimates of Class 3 stack emissions from the DGDP were determined assuming that the NPI and Brown Coal Industry Research Program (BCIRP) emission factors for pulverised brown coal combustion in conventional power stations are representative of the emissions that will result from the DGDP. The emissions estimates for several of the Class 3 Indicators indicate that the in-stack concentrations are lower that the GLC Design Criteria specified in the SEPP prior to applying a dilution factor. With the application of a dilution factor all of the estimated Class 3 emissions were typically <1% of the Design Criteria GLC (for the operation of the DGDP in isolation).

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ASSESSMENT FOR THE POTENTIAL OF CLASS 3 AIR POLLUTANTS FROM THE 600 MW DUAL GAS DEMONSTRATION PROJECT

1. INTRODUCTION

HRL Developments (HRLD) intends to submit a Works Approval Application to EPA Victoria for the construction of the Dual Gas Demonstration Project (DGDP). As part of the Works Approval process an air quality assessment is required.

HRL Technology (HRLT) previously conducted air quality assessments for the Latrobe Valley region, including dispersion modelling of NO_2 and SO_2 emissions for the 600 MW DGDP.[1] Modelling of the Ground Level Concentrations (GLCs) of NO_2 and SO_2 was conducted as they are expected to be the key air pollutants with respect to ambient air quality.[2] Under the State Environment Protection Policy (SEPP) for Air Quality Management (AQM) NO_2 and SO_2 are classified as Class 1 Indicators, which are common or widely distributed air pollutants. The SEPP places particular importance on Class 3 Indicators, which are defined as extremely hazardous substances, and Maximum Design Criteria are specified. Additionally, the SEPP states that generators of Class 3 Indicators are required to reduce those emissions to the Maximum Extent Achievable (MEA).

Detailed air dispersion modelling of Class 3 Indicators has not been conducted for the 600 MW DGDP. Consequently, HRLD has requested that HRLT review the potential for Class 3 Indicators being emitted from the DGDP.

2. BACKGROUND

The DGDP is proposed to be a 600 MW power station consisting of two Combined Cycle Gas Turbine (CCGT) units with a single air cooled condenser and two Integrated Drying and Gasification (‘gasifier’) plants. The proposed DGDP site is located within the existing Energy Brix Australian Corporation (EBAC) complex.

The primary fuel of the DGDP is synthesis gas (‘syngas’), which will be generated from brown coal. Natural gas will be used as the start-up and make-up fuel. It is expected that upon the completion of the second gasifier that the gas turbines will operate on syngas about 85% of the time, with up to 10% of the time with the gas turbines operating on natural gas (with 5% downtime). HRLD estimates the composition of the gaseous fuels to be:

1. Syngas - variable composition; e.g., H_2O 13%, N_2 36%, H_2 18%, CO 18%, CO_2 11%, CH_4 4% (25 bar, 260ºC, %volume). Note the sulfur content of the syngas is very small; i.e., in Latrobe Valley coals the sulfur is typically 0.3% (dry basis) with some of this captured in fly ash. SO_2 emissions become significant after combustion.

2. Natural Gas - variable composition, but primarily methane (CH_4) and ethane (C_2H_6); in Victoria, comprising approximately 90% and 5% by volume respectively.

The SEPP (AQM) defines air quality indicators as Class 1, 2, 3 or unclassified indicators depending on their likely distribution, toxicity, odour characteristic or hazard rating. This

[1] Thornton, D. (June 2010). *Air Quality Modelling Assessment – 600 MW Dual Gas Demonstration Project in Latrobe Valley*. HRL Technology, Report HLC/2009/430/R4

[2] Pickett, M. (September 2009). *Desktop Air Quality Assessment*. Sinclair Knight Merz.

reflects the current understanding of the health effects of the pollutants, thereby ensuring that beneficial uses of the environment are protected.

Class 1 Indicator means a substance which is common or widely distributed (e.g. NO_2) and may threaten the beneficial uses of both local and regional air environments.

Class 2 Indicator means a waste which is hazardous that may threaten the beneficial uses of the air environment by virtue of its toxicity, bio-accumulation or odorous characteristics.

Class 3 Indicator means a waste which is an extremely hazardous substance that may threaten the beneficial uses of the air environment due to its carcinogenic, mutagenic, teratogenic, highly toxic or persistent characteristic.

Schedule A of the SEPP (AQM) provides Design Criteria for the purpose of assessment of proposals for new emission sources or modifications to existing sources (see Table 1).

Table 1: Class 3 Indicators

Substance	**Reason for Classification**	**Averaging Time**	**Design Criteria (mg/m3)**	**Design Criteria (ppm)**
Acrolein	USEPA Extremely Toxic	3-minute	0.00077	0.00033
Acrylonitrile	USEPA Group B1 Carcinogen	3-minute	0.014	0.0067
Alpha Chlorinated Toluenes and Benzoyl Chloride	IARC Group 2A Carcinogen	3-minute	0.017	0.0033
Arsenic and compounds	IARC Group 1 Carcinogen	3-minute	0.00017	
Asbestos	IARC Group 1 Carcinogen	3-minute	0.33 fibres/L	
Benzene	IARC Group 1 Carcinogen	3-minute	0.053	0.017
Beryllium and Beryllium Compounds	IARC Group 1 Carcinogen	3-minute	0.000007	
1,3-Butadiene	IARC Group 2A Carcinogen	3-minute	0.073	0.033
Cadmium and Cadmium Compounds	IARC Group 1 Carcinogen	3-minute	0.000033	
Chromium VI Compounds	IARC Group 1 Carcinogen	3-minute	0.00017	
1,2-dichloroethane (ethylene dichloride)	Mutagen (USEPA)	3-minute	0.13	0.033
Dioxins and Furans (as TCDD I-TEQs)	IARC Group 1 Carcinogen	3-minute	3.7E-09	
Epichlorohydrin	IARC Group 2A Carcinogen	3-minute	0.025	0.0067
Ethylene Oxide	IARC Group 1 Carcinogen	3-minute	0.006	0.0033
Hydrogen Cyanide	USEPA Extremely Toxic	3-minute	0.37	0.33
MDI (Diphenylmethane diisocyanate)	USEPA Extremely Toxic	3-minute	0.00007	
Nickel and Nickel Compounds	IARC Group 1 Carcinogen	3-minute	0.00033	0.00017
Polycyclic Aromatic Hydrocarbons (PAH) (as BaP)	IARC Group 2A Carcinogen	3-minute	0.00073	
Pentachlorophenol	USEPA Extremely Toxic	3-minute	0.0017	
Phosgene	USEPA Extremely Toxic	3-minute	0.013	0.0033
Propylene Oxide	USEPA Group B1 Carcinogen	3-minute	0.16	0.067
Radionuclides			ALARA	
Respirable crystalline silica (inhalded in the form of quartz or crystobalite) (measured as PM2.5)	IARC Group 1 Carcinogen	3-minute	0.00033	
TDI (toluene-2,4-diisocyanate and toluene-2,6-diisocyanate)	USEPA Extremely Toxic	3-minute	0.00007	
Trichloroethylene	IARC Group 2A Carcinogen	3-minute	0.9	0.17
Vinyl Chloride	IARC Group 1 Carcinogen	3-minute	0.043	0.017

*ALARA means as low as reasonably achievable.

3. GASIFICATION PROCESSES

The key components of the DGDP that will contribute to emissions to air are the:

1. ***Combined Cycle Gas Turbine (CCGT)*** – emissions resulting from the combustion of syngas or natural gas when the gasifier is not in operation or a combination of natural gas and syngas. Each CCGT will account for about 1,954 t/h of gas flow.

2. ***Char Combustors*** – emissions resulting from the combustion of the char exiting the gasifiers. Natural gas can also be combusted as required. Each char combustor will result in about 149 t/h of gas flow.

3. ***Flare*** – typically the flare will only be used intermittently (e.g. start-up or emergency shut-down). Therefore, the flare should not typically be a significant source of emissions.

4. ***Air Pre-Heaters*** **–** there will be two stacks for the natural gas fired air heater plants. These will not be a significant source of emissions (about 9 t/h total flow per stack) in comparison to the CCGTs.

5. ***Pre-Dryers*** – there will be two stacks for the natural gas fired steam heating plants. These will not be a significant source of emissions (about 102 t/h) in comparison to the CCGTs.

Gasifier plant, such as the DGDP, is inherently different from pulverised fuel combustors or fluidised bed combustors where the coal is combusted in an overabundance of air in an oxidising environment. In the DGDP the coal feedstock is input into the gasifier to produce syngas via reaction with steam and oxygen at high temperature and pressure in a reducing (oxygen starved) atmosphere. The syngas is then combusted in the gas turbine to produce power.

3.1 DGDP Process Description

The Integrated Drying and Gasification Combined Cycle (IDGCC) process merges gasification with gas cleaning, synthesis gas conversion and turbine power technologies to produce clean and affordable energy. This integration of energy conversion processes provides more complete utilisation of energy resources and offers high efficiencies and reduced pollution levels.

The centrepieces of this process are therefore the two following units:

- Integrated Drying and Gasification Plant (where the coal is dried and gasified); and
- Combined Cycle Power Plant (where the power is generated).

Figure 1 shows the main operational flows of the proposed power station using the IDGCC process.

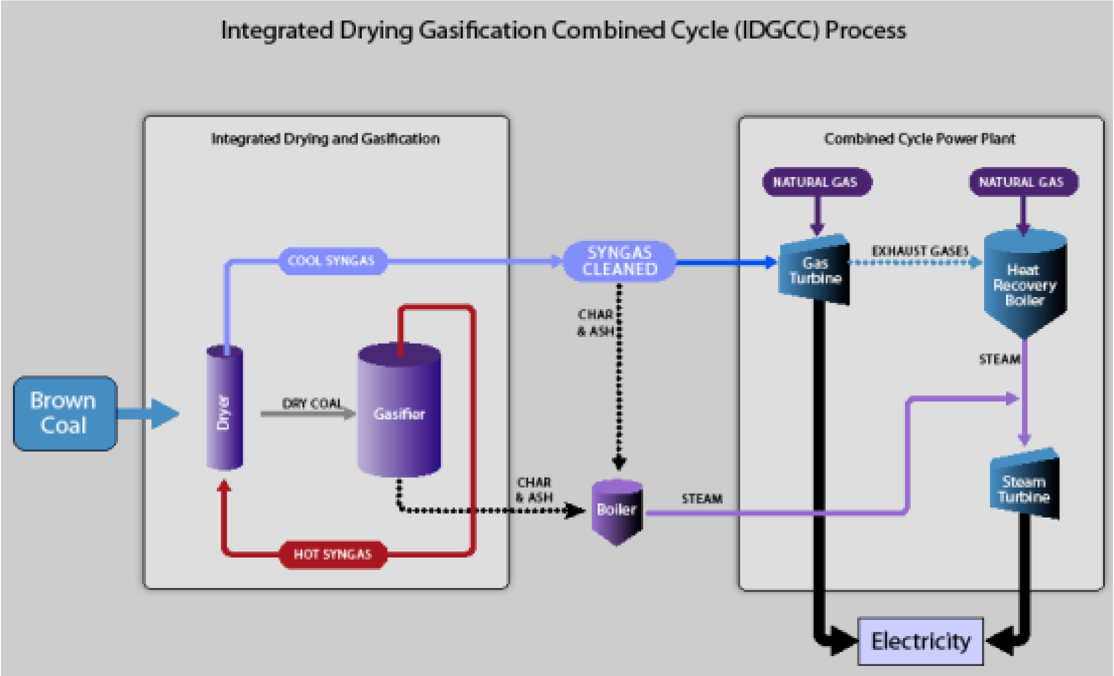

Figure 1: Integrated Drying Gasification Combined Cycle Process

3.1.1 *Integrated Drying and Gasification Plant – Syngas Production*

Syngas for use in the gas turbines will be generated by the IDGCC technology, where:

- Coal is dried under pressure during start up by natural gas and then once the gasification process has commenced, by hot syngas;
- Hot syngas is generated by gasification of the dried coal;
- Hot syngas is cooled by the drying of the coal; and
- Cooled syngas is filtered and conditioned, suitable for combustion in the gas turbines.

A gasifier differs from a combustor in that the amount of air or oxygen available inside the gasifier is carefully controlled so that a relatively small portion of the fuel burns completely. This "partial oxidation" process provides heat. Rather than burning, most of the coal is chemically broken apart by the gasifier's heat and pressure, setting into motion chemical reactions that produce "syngas". This syngas is primarily hydrogen, carbon monoxide and other gaseous constituents; the composition of which depends upon the conditions in the gasifier and the type of coal used.

Minerals in coal separate and remain at the bottom of the gasifier. Nitrogen oxides, another potential pollutant, are not formed in the oxygen-deficient environment of the gasifier; instead, ammonia is created by nitrogen-hydrogen reactions. The ammonia is to be stripped out of the gas stream prior to combustion in the gas turbine, to reduce NO_x formation.

3.1.2 *Combined Cycle Power Plant – Power Generation*

The primary fuel used for power generation will be synthetic gas (syngas) generated from brown coal, and natural gas is expected to be used as start-up fuel, as well as a supplementary fuel. The Gas Turbines generate power from the combustion of syngas, natural gas, or a combination of both gases. The syngas is cleaned of ammonia and particulate matter and is burned as fuel in a combustion turbine, much like natural gas is burned in a turbine. Additional power is capable of being generated by steam turbines, powered by steam raised by:

- Combustion of exhaust gases (from gas turbines) in the Heat Recovery Steam Generator with supplementary heat input from natural gas firing; and
- Combustion of char and ash residues from the Integrated Drying and Gasification Plant.

3.1.3 *Environmental controls*

The Table below presents the key processes and associated environmental controls involved in the IDGCC process.

Table 2: Key Processess and Associated Environmental Controls

Key process steps	Key inputs	Key outputs	Key environmental controls
Integrated Drying and Gasification Plant	• Brown Coal • Energy	• Char • Ash • Clean syngas	• Contained system; • Monitoring and process control systems
Combustion of Char	• Char	• Steam	• Bag filters; • Monitoring and process control systems
Combined Cycle Power Plant	• Clean syngas • Steam • Natural Gas • Water	• Electricity	• Steam injectors (for NOx control), • Ammonia scrubbers, Stack heights & velocities to ensure compliance; • Monitoring & process control systems

3.1.4 *Syngas Cleaning System*

The filtration technology employed is a porous ceramic in the form of a hollow candle. Dust is collected on a fine outer layer, whilst the clean syngas passes through. Dust is removed from the candle by reverse flow pulse – see Figure 2.

Efficient removal of particulates from the syngas is essential to avoid damage to the gas turbine. As a result, emissions of particulates to the atmosphere from the combined cycle plant are expected to be negligible compared to current coal fired Latrobe Valley power stations.

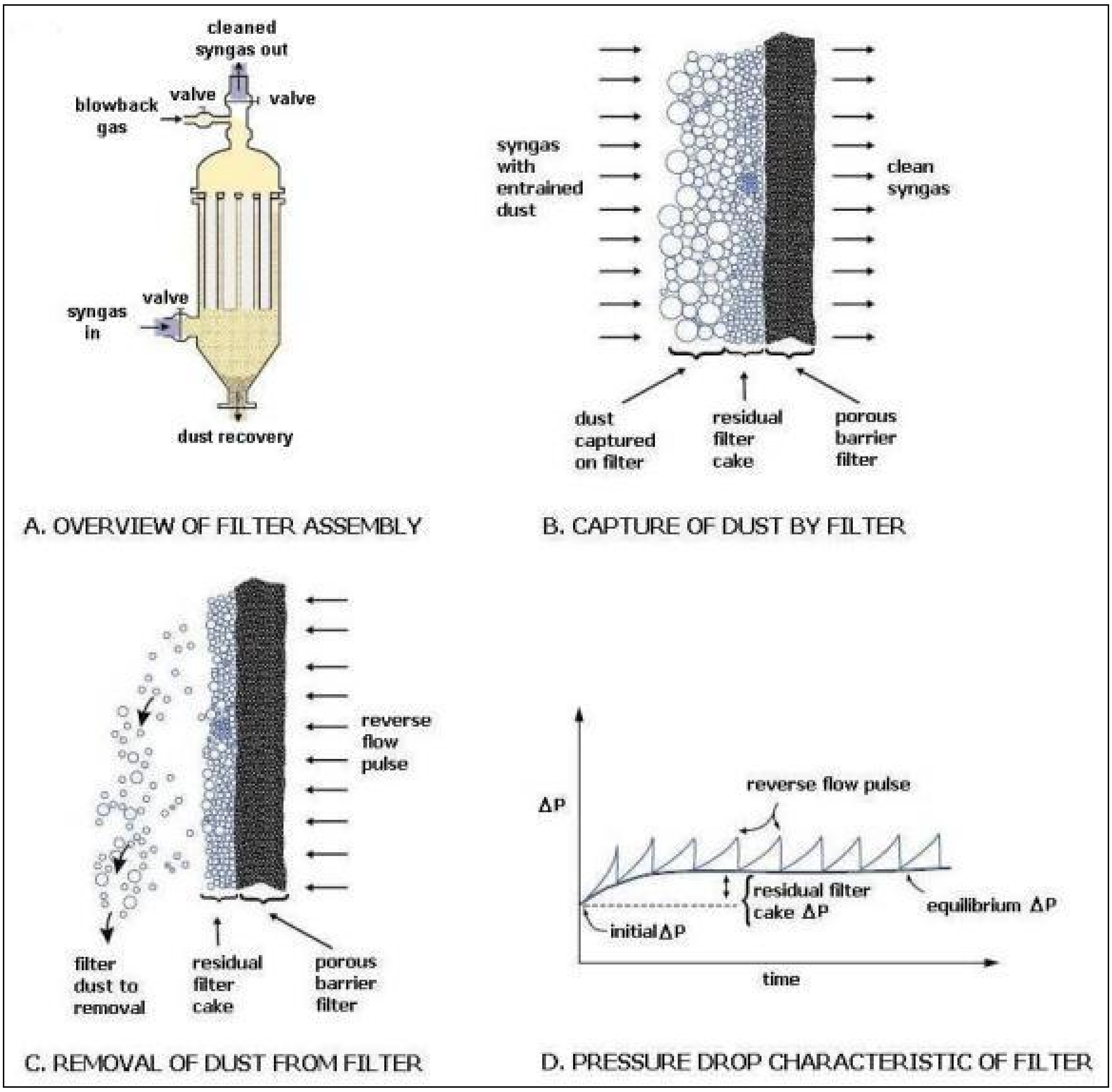

Figure 2: Syngas cleaning system

3.1.5 Flue Gas Cleaning System – Char Combustion

Char and ash collected from the particulate filtration system and from the gasifier hopper are proposed to be burnt in a boiler to raise steam.

The ash from this combustion will be essentially identical to the ash from other Latrobe Valley power stations. This ash will be collected by bag filter technology. The efficiency of bag filtration is higher than that of electrostatic precipitators (as used on other Latrobe Valley boilers). Bag filters are not used on conventional Latrobe Valley Power stations due to the high gas flow associated with combustion of the high moisture content brown coal.

4. NATIONAL POLLUTANT INVENTORY EMISSION FACTORS

4.1 General

The requirement for a facility to report emissions of pollutants to the National Pollutant Inventory (NPI) is triggered based on defined thresholds in three different categories. Estimates of emissions of NPI-listed substances to air, water and land should be reported for each substance that triggers a threshold. The list of reportable substances and detailed information on thresholds are contained in the NPI Guide.

NPI Category 1 and 1a Substances

Category 1 contains a broad range of substances that are typically present in materials used for production. The threshold for this Category is the "use" of 10 tonnes or more per year of a Category 1 substance. For NPI purposes "use" is defined as the handling, manufacture, import, processing, coincidental production, or other use of a substance.

Category 1a only contains Total Volatile Organic Compounds (TVOC). The NPI defines TVOC as:

> *Any chemical compound based on carbon chains or rings (and also containing hydrogen) with a vapour pressure greater than 0.01kPa at 293.15K (20°C), that participate in atmospheric photochemical reactions.*

Substances that are specifically excluded from this definition are carbon dioxide, methane, acrylamide, benzene hexochloro, biphenyl, chlorophenols, n-butyl phthalate, ethylene glycol, di-(2-ethylhexyl) phthalate (DEHP), 4,4-methlyene bis 2,4 aniline (MOCA), Methylenebis, Phenol, and toluene-2,4-diisocyanate (which is a Class 3 Indicator).

The thresholds for Category 1a compounds are:

- Use of 25 tonnes or more per year of TVOC; or
- A bulk storage facility that uses more than 25 tonnes per year AND has a design storage capacity greater than 25 kilo tonnes of material containing VOC.

Substances in proprietary mixtures are not reported to the NPI or considered for reporting thresholds unless the substance is specified in a Material Safety Data Sheet or the facility operator could reasonably be expected to know it is contained in the mixture.

NPI Category 2a Substances

This Category of substances contains a group of substances that are common products of combustion or other thermal process. The NPI reporting thresholds for Category 2a substances are:

- Burning of 400 tonnes or more fuel or waste in a year; or
- Burning 1 tonne or more of fuel or waste in an hour at any time during the reporting year.

If any of these reporting thresholds are exceeded then all emissions of the relevant substances must be reported to the NPI.

Category 2a NPI substances are:

- Carbon monoxide (CO)
- Fluoride compounds
- Hydrochloric acid (HCl)
- Oxides of nitrogen (NO_x)
- Particulate matter 10 micrometers or less in diameter (PM_{10})
- Polycyclic aromatic hydrocarbons (PAH)
- Sulfur dioxide (SO_2)
- Total Volatile Organic Compounds (TVOC)

NPI Category 2b Substances

This Category also contains substances that are common products of combustion or other thermal processes and includes all Category 2a substances. It also includes metals and compounds emitted when fuels (especially coal and oil) are burnt. The NPI thresholds for Category 2b substances are:

- Burning 2,000 tonnes or more of fuel or waste in a year;
- Consuming 60,000 megawatt hours or more of energy (e.g. electricity) in a year;
- A facility that has maximum potential power consumption of 20 megawatts or more at any time in the year.

If any of these reporting thresholds are exceeded then all emissions of the relevant substances must be reported to the NPI.

Category 2b substances are:

- Arsenic & compounds
- Beryllium & compounds
- Cadmium & compounds
- Carbon monoxide
- Chromium (III) compounds
- Chromium (VI) compounds
- Copper & compounds
- Fluoride compounds
- Hydrochloric acid
- Lead & compounds
- Magnesium oxide fume
- Mercury & compounds
- Nickel & compounds
- Nickel carbonyl ($Ni(CO)_4$)
- Nickel subsulfide (NiS)
- Oxides of nitrogen (NO_x)
- Particulate matter 10 micrometers or less in diameter (PM_{10})
- Polychlorinated dioxins and furans
- Polycyclic aromatic hydrocarbons
- Sulfur dioxide (SO_2)
- Total Volatile Organic Compounds (TVOC)

Category 3 Substances

Category 3 refers or applies to the actual amount of total nitrogen and total phosphorus emitted to water.

4.2 NPI Emission Estimation Methods

In general, there are four types of emission estimation techniques (EET) that can be used to estimate emissions from a facility for NPI reporting. The four types described in the NPI Guide are:

1. sampling or direct measurement
2. mass balance
3. fuel analysis or other engineering calculations
4. emission factors

A series of Emission Estimation Technique Manuals (EETM) are available from the NPI for a variety of industries. Manuals that are typically applicable to Electricity Generators are:

- NPI Guide, Version 5.1, February 2010;
- NPI Emission Estimation Technique Manual for Fossil Fuel Electric Power Generation Version 2.4, 15 March 2005;
- NPI Emission Estimation Technique Manual for Combustion Boilers, Version 3.1, June 2008;
- NPI Emission Estimation Technique Manual for Mining. Version 2.3 (December 2001); and
- NPI Emission Estimation Technique Manual for Combustion Engines Version 3.0 (June 2008).

4.3 HRLT's Relevant Experience with the NPI

HRLT was commissioned by the Department of Environment and Water Resources (DEWR) in 2007 to revise the Combustion Boilers and Combustion Engines EETMs. It was identified by Australian industry that these EETMs in their prior format may not have adequately addressed the equipment used by Australian industry nor provide adequate emission factors for the combustion of Australian-sourced fuels (since the majority of emissions factors used for NPI reporting are sourced from the USEPA). The aim of this work was to determine and develop new Australian-based emission factors for estimation of emissions of NPI reportable substances.

As part of this work emissions data was requested from all facilities in Australia that the NPI and DEWR identified as operating boilers and combustion engines. From the data received it was found that the vast majority of facilities were using the NPI Emission Factors from the EETMs for emissions estimates. Very few facilities were directly measuring emissions for NPI reporting or performing mass balances or other engineering calculations.

HRLT also conducted a literature review and found that very limited information could be sourced for emission studies conducted in Australia. Additionally, publicly available emission studies typically relied on the USEPA AP-42 emission factors or those from the relevant Australian NPI handbook (which typically were compiled from the AP-42 factors). Due to the costs associated with conducting stack emissions testing, especially for a wide range of emitted pollutants, it is not unexpected that such public studies have not typically been conducted independently in Australia by industrial facilities or industry groups.

HRLT performs stack emissions testing for many facilities throughout Australia (for Electricity Generators and other industrial clients). In HRLT's experience most facilities perform limited stack emissions measurements. For example, EPA license requirements for a coal fired power station may only require that stack measurements of CO, NO_x, SO_x, and Particulate Matter are measured and reported to the EPA on a routine basis (e.g. twice annual measurement). Power stations in Australia do not generally perform stack sampling for Class 3 Indicators. Rather emissions of Class 3 Indicators are typically determined using the NPI emission factors from the EETM for Fossil Fuel Electric Power Generation.

4.4 Class 3 Indicators and Their Associated NPI Classification

Relevant NPI emission factors are not available for all of the Class 3 Indicators listed in Table 1. Additionally, not all of the Class 3 Indicators are listed as NPI reportable pollutants (see Table 3).

Table 3: Class 3 Indicators and Associated NPI Classification

Substance	**NPI Classification**
Acrolein	Class 1
Acrylonitrile	Class 1
Alpha Chlorinated Toluenes and Benzoyl Chloride	
Arsenic and compounds	Class 1 & 2b
Asbestos	
Benzene	Class 1
Beryllium and Beryllium Compounds	Class 1 & 2b
1,3-Butadiene	Class 1
Cadmium and Cadmium Compounds	Class 1 & 2b
Chromium VI Compounds	Class 1 & 2b
1,2-dichloroethane (ethylene dichloride)	Class 1
Dioxins and Furans (as TCDD I-TEQs)	Class 2b
Epichlorohydrin	
Ethylene Oxide	Class 1
Hydrogen Cyanide	
MDI (Diphenylmethane diisocyanate)	
Nickel and Nickel Compounds	Class 1 & 2b
Polycyclic Aromatic Hydrocarbons (PAH) (as BaP)	Class 2a & 2b
Pentachlorophenol	
Phosgene	
Propylene Oxide	
Radionuclides	
Respirable crystalline silica (inhalded in the form of quartz or crystobalite) (measured as PM2.5)	Class 2a & 2b (as PM2.5)
TDI (toluene-2,4-diisocyanate and toluene-2,6-diisocyanate)	Class 1
Trichloroethylene	Class 1
Vinyl Chloride	Class 1

The Category 2a and 2b substances reportable to the NPI are common products of combustion or thermal processes, whereas the Category 1 and 1a reporting thresholds are based on substance usage (e.g. chemical usage) and Category 3 substances are pollutants emitted to water. Therefore, it's the Category 2a and 2b substances that are expected to be generated during a combustion process and will likely be most applicable to the air emissions from the DGDP.

NPI emission factors for brown coal combustion for the Class 3 Indicators are presented in Table 4. It should be noted that the emission factors presented in Table 4 are for the combustion of brown coal in pulverised fuel boilers in an oxidising environment. Therefore, these emission factors may not be representative of the operating conditions for the DGDP (i.e. reducing conditions during the gasification process, combustion of the syngas in the turbine, and combustion of the char). NPI emission factors for gasification processes (i.e. integrated gasification combined cycle) are not available.

Table 4: NPI Emission Factors for Brown Coal Combustion

Substance	EF for Victorian Brown Coal Combustion	EF For Brown Coal Combustion
Acrolein	N/A	N/A
Acrylonitrile	N/A	N/A
Alpha Chlorinated Toluenes and Benzoyl Chloride	N/A	N/A
Arsenic and compounds	3.0E-06	3.0E-06 $2.73*[(C/A)*PM]^{0.85}$
Asbestos	N/A	N/A
Benzene	3.6E-06	3.6E-06
Beryllium and Beryllium Compounds	1.7E-06	1.7E-06 $1.31*[(C/A)*PM]^{1.1}$
1,3-Butadiene	N/A	N/A
Cadmium and Cadmium Compounds	2.5E-06	2.5E-06 $2.17*[(C/A)*PM]^{0.5}$
Chromium VI Compounds	6.1E-06	6.1E-06 $0.05*2.6*[(C/A)*PM]^{0.58}$
1,2-dichloroethane (ethylene dichloride)	N/A	N/A
Dioxins and Furans (as TCDD I-TEQs)	8.8E-10	8.8E-10
Epichlorohydrin	N/A	N/A
Ethylene Oxide	N/A	N/A
Hydrogen Cyanide	N/A	N/A
MDI (Diphenylmethane diisocyanate)	N/A	N/A
Nickel and Nickel Compounds	3.4E-05	3.4E-05 $2.84*[(C/A)*PM]^{0.48}$
Polycyclic Aromatic Hydrocarbons (PAH) (as BaP)	8.0E-07	8.0E-07
Pentachlorophenol	N/A	N/A
Phosgene	N/A	N/A
Propylene Oxide	N/A	N/A
Radionuclides	N/A	N/A
Respirable crystalline silica (inhalded in the form of quartz or crystobalite) (measured as PM2.5)	N/A	N/A
TDI (toluene-2,4-diisocyanate and toluene-2,6-diisocyanate)	N/A	N/A
Trichloroethylene	3.6E-06	N/A
Vinyl Chloride	N/A	N/A

C = concentration of metal in the coal, part per million by mass or mg/kg (as received basis)
A = weight fraction of ash in the coal
PM = facility specific emissions factor for total particulate matter (kg/GJ)

5. EMISSION STUDIES FOR GASIFICATION PROCESSES

Due to differences between the operation of gasification systems and from conventional combustion (and since there are no NPI emission factors for coal fired gasification plant) specific emission studies for pollutants emitted from coal gasification plant was sought.

5.1 Previous HRL Studies

HRL have previously conducted studies on the emissions to air from the combustion of gasification product gas and char. This has included measuring stack gases from the pilot plant Coal Gasification Development Unit (CGDU) located in Mulgrave and the demonstration plant Coal Gasification Development Facility (CGDF) located in Morwell.

HRL was required to measure air pollutants from the CGDF under the EPA RD&D Approval (Approval RD26791) and report the results quarterly to the EPA. In accordance to Works Condition No 8 HRL was required to measure a range of major and trace components (including CO, HCl, NH_3, SO_2, NO, and NO_2) from the gas turbine exhaust stack. Emissions from the flare were calculated based on analytical data for the product gas being flared.

Works Condition No 9 also required that the monitoring program make specific provision for assessing the emissions to atmosphere of oxides of nitrogen from the CGDF and the effectiveness of various methods to reduce these emissions.

Therefore, significant work has been undertaken to measure emissions in accordance to the EPA Works Conditions. However, none of the compounds that were routinely measured are Class 3 Indicators. As such, detailed studies on emissions of Class 3 Indicators from the CGDU or CGDF were not undertaken. Attempts were made to use gas chromatography to measure trace pollutants during the operation of the CGDF during the 1 October 1997 to 31 December 1997 period, but were not successful. The quarterly reports that were submitted to the EPA regarding the operation of the CGDF include the following:

- Fitzgerald, W.R. (1996), *Report on the operation of the CGDF at Morwell for the period July to September 1996*, HRL Technology, Report No. HLC/96/252;
- Fitzgerald, W.R. (1996), *Report on the operation of the CGDF at Morwell for the period October to December 1996*, HRL Technology, Report No. HLC/96/334;
- Fitzgerald, W.R. (1997), *Report on the operation of the CGDF at Morwell for the period April to June 1997*, HRL Technology, Report No. HLC/97/383;
- Fitzgerald, W.R. (1997), *Report on the operation of the CGDF at Morwell for the period January to March 1997*, HRL Technology, Report No. HLC/97/506;
- Fitzgerald, W.R. (1997), *Report on the operation of the CGDF at Morwell for the period July to September 1997*, HRL Technology, Report No. HLC/97/599;
- Fitzgerald, W.R. (1997), *Report on the operation of the CGDF at Morwell for the period July to September 1997*, HRL Technology, Report No. HLC/97/599;

- Fitzgerald, W.R. (1998), *Report on the operation of the CGDF at Morwell for the period October to December 1997,* HRL Technology, Report No. HLC/97/653.

5.2 External Studies

There is not a significant amount of publically available information from national or international studies of emissions from integrated gasification combined cycle plant that measured the Class 3 Indicators listed in Table 1. Due to the limited number of electricity generators operating commercial scale IGCC plant it is not unexpected that there is limited publically available emissions studies. For example, according to the United States Department of Energy (DOE) National Energy Technology Laboratory (NETL) database in 2007 there were a total of 144 plants around the world that operated gasification systems that generate electricity (accounting for only about 29,000 MW of installed global capacity)[3].

As mentioned previously in Section 4.3 there are limited studies available for emissions from combustion boilers either from Australian or international sources. It was found that most publically available studies relied on the USEPA AP-42 emission factors or Australian NPI handbook factors (which typically were compiled from the AP-42 factors). Therefore, there are not readily available emission factors for IGCC plant.

In a review conducted by the US DOE and Science Applications International Corporation in 2002 regarding the environmental assessment of IGCC power systems it was determined that IGCC plants have achieved the lowest levels of criteria pollutant air emissions (NOx, SOx, CO, PM10) of any coal-fired power plants in the world. Additionally, it was found that emissions of trace hazardous air pollutants are extremely low, comparable with those from direct-fired combustion plants that use advanced emission control technologies.[4] It was stated that most trace pollutants are removed with the slag/bottom ash or in the particulate control equipment.

An in depth study of the major environmental aspects of gasification-based power generation was published by the US DOE NETL in December 2002.[5] It was found that data on the chemical and physical forms of trace elements during coal gasification is quite limited compared to that from conventional boilers. However, some information from thermodynamic equilibrium modelling studies, bench- and pilot-scale units, and commercial-scale IGCC plants was sourced.

A variety of computer-based thermodynamic equilibrium studies have been performed to identify the chemical and physical forms of vapor-phase trace elements likely to be produced in a gasification process. These studies determined that most trace metals will most likely be removed from the syngas and discharged in the solid and aqueous effluents. The most volatile species of the coal, such as mercury, selenium, arsenic, cadmium, and boron would likely remain in the gas stream. The thermodynamic models indicated that the trace metals are generally more volatile under the reducing conditions of gasification than in oxidizing environments, possibly because volatile gaseous compounds, such as chlorides, sulphides, and hydroxides, are more stable in reducing atmospheres.

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[3] http://www.netl.doe.gov/technologies/coalpower/gasification/database/database.html

[4] Ratafia-Brown, J.A., L.M. Manfredo, J.W. Hoffmann, M. Ramezan, and G.J. Stiegel (2002), *An Environmental Assessment of IGCC Power System*, Science Applications International Corpoeration and US DOE/National Energy Technology Laboratory, Nineteenth Annual Pittsburgh Coal Conference.

[5] Ratafia-Brown, J.A., L.M. Manfredo, J.W. Hoffmann, M. Ramezan (2002), *Major Environmental Aspects of Gasification-Based Power Generation Technologies, Final Report* (2002), US Department of Energy, National Energy Technology Laboratory.

In the review conducted for the DOE[5] trace organic emissions from IGCC plant were compared with those produced by conventional coal-fired power plants, as well as natural gas-fired combustion turbines. The comparison with natural gas fired turbines was made since IGCC technology incorporates a combustion turbine (CT) in the power cycle. It was found that little corroborating data was available on individual trace organic releases to the air from gasification systems, but detailed test results from the Louisiana Gasification Technology Incorporation (LGTI) IGCC plant and Wabash River IGCC plant was used to provide perspective on the types and levels likely to be seen.

The results generally indicated extremely low levels of trace organic emissions, in-line with emissions expected from conventional coal-fired plants. Data from the Wabash River IGCC plant, while higher than measured LGTI emissions, also supports relatively low levels of emissions.

The LGTI test results did not identify any significant dioxin or furan emissions in the stack gas. This is in agreement with the belief that dioxins and furans are not likely to be formed in gasification systems since the high temperatures in the gasifier should destroy any dioxin/furan compounds or precursors, and the lack of oxygen in the reducing environment should limit the formation of free chlorine.

The data from IGCC power plants indicated that their organic emissions are extremely low. Detailed HAPs measurements taken at the LGTI IGCC plant indicates that IGCC generally performs better than a natural gas-fired turbine from the standpoint of HAPs emissions. The LGTI emissions were typically an order-of-magnitude lower than the average AP-42 HAP emission factors. Additionally, it was found that most of the trace elements present in the coal were removed in the LGTI IGCC process.[6]

[6] Williams, A., B. Wetherold, and D. Maxwell (1996), *Trace Substance Emissions from a Coal-fired Gasification Plant; Summary Report*, Final report, Electric Power Research Institute.

6. PREVIOUS AIR DISPERSION MODELLING OF CLASS 3 INDICATORS IN THE LATROBE VALLEY

The Brown Coal Industry Research Program (BCIRP) examined and established levels of trace emissions emitted from Latrobe Valley power stations. In recent years, HRL Technology determined emissions for Class 2 and 3 Indicators using a combination of emission factors from the BCIRP Trace Emissions from Brown Coal Study and those contained in the National Pollution Inventory (NPI) Manual for estimating emissions from fossil fuel electric power generation.[7]

HRLT has previously conducted air dispersion modelling of Class 1, Class 2, and Class 3 Indicators in the Latrobe Valley emitted from the existing brown coal fired power stations and paper mills.[7] Through the use of air quality modelling the amounts of pollutants expected to be found at ground level were predicted and an assessment was made as to whether the levels of Class 1, 2, and 3 Indicators emitted pose a risk to the health of the residents of the Latrobe Valley. The ground level concentrations (GLCs) of the Class 3 Indicators in the Latrobe Valley predicted from the air dispersion modelling were compared with the SEPP (Air Quality Management) Design Criteria.

For this modelling data was included from a previous study which examined the level of Class 3 Indicators emitted to demonstrate compliance with the Maximum Extent Achievable (MEA) requirement of the SEPP (AQM).

Where available, emission levels for Class 3 Indicators were modelled using available data derived from the emissions measurements conducted for the Brown Coal Industry Research Program (BCIRP) which examined and established trace emissions from Latrobe Valley power stations.

A summary of the known hazardous substances commonly emitted from power stations is presented in Table 5.[7] From the list of all of the Class 3 Indicators (see Table 1) only 10 (including PAH) of the Class 3 Indicators are commonly emitted during fossil fuel combustion. The levels of Class 3 Indicators measured as being emitted from brown coal fired power stations are very low.

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[7] Delaney, W. (June 2007). *Ground Level Concentrations of State Environment Protection Policy Class 1, 2, and 3 Indicator Air Emissions in the Latrobe Valley*. HRL Technology, Report HLC/2007/087. Available from: www.powerworks.com.au/HLC2007087.pdf

Table 5: Hazardous Air Pollutants Detected in Emissions from Fossil-fuel Fired Power Stations

Substance	Class 3 Indicator?	Substance	Class 3 Indicator?
Organic		***Inorganic***	
Benzo-a-pyrene	No	Antimony Compounds	No
Benzene	***Yes***	***Arsenic Compounds***	***Yes***
Biphenyl	No	***Berylium Compounds***	***Yes***
bis-(2-ethlhexyl)-phathalate	No	***Cadmium Compounds***	***Yes***
Cabon disulphide	No	***Chromium Compounds***	***Yes***
Carbon tetrachloride	No	Cobalt Compounds	No
Carbonyl sulphide	No	Copper Compounds	No
Chlorobenzene	No	Lead Compounds	No
Chloroform	No	Manganese Compounds	No
Cyclohexane	No	Mercury Compounds	No
dibenzofurans	***Yes (Dioxins & Furans)***	***Nickel Compounds***	***Yes***
1,4-dichlorobenzene (p)	No	Selenium Compounds	No
Ethylbenzene	No	Ammonia	No
Formaldehyde	No	Cyanide	No
Hexachlorobenzene	No	Hydrogen Sulfide	No
Methyl Ethyl Ketone	No	Fluoride Compounds	No
Naphthalene	No	Hydrogen Chloride	No
n-Hexane	No	Chlorine	No
Pentachlorophenol	***Yes***	***Others***	
Phenol	No	Carbon Monoxide	No
2,3,7,8-tetrachlorodibenzo-p-dioxin	***Yes (Dioxins & Furans)***	Oxides of Nitrogen	No
Tetrachloroethylene	No	Sulphur Dioxide	No
Toluene	No	Particulate Matter (<10 um)	No
Trichloroethylene	***Yes***	***Particulate Matter (<2.5 um)***	***Yes (as Respirable Crystaline Silica)***
2,4,5-trichlorophenol	No		
Styrene	No		
Xylene	No		

6.1 Modelling Results of Class 3 Indicators in the Latrobe Valley

The results of the modelling[7] of Class 3 Indicators for existing emission sources is summarised in the following Sections of the report.

6.1.1 Arsenic (As) and Arsenic Compounds

The arsenic concentrations that have been measured in Latrobe Valley power station stacks are from 0.8 to 12.8 µg/m^3. Arsenic concentrations measured in the paper mill stacks are typically 0.1 to 2 µg/m^3.

The modelling results showed that the predicted 99.9 percentile 3 minute GLCs in the townships of Moe, Morwell and Traralgon were an order of magnitude below the 3 minute Design Criteria of 0.17 µg/m^3. The highest 99.9 percentile 3 minute GLCs in the vicinity of Jeeralang Hill of 0.032 µg/m^3.

Therefore it's expected that since the emissions of arsenic from all of the existing brown coal fired power stations and paper mills in the Latrobe Valley result in a maximum 99.9 percentile 3-minute GLC of 0.032 µg/m^3 (about 19% of the Design Criteria), that the addition of the DGDP to the airshed would not result in the Design Criteria being exceeded.

6.1.2 Berylium (Be) and Berylium Compounds

The concentrations of Berylium that have been measured in Latrobe Valley power station stacks are small from 0.78 to 1.3 µg/m^3. The modelled contributions of the Latrobe Valley Generators and paper mills to predicted 99.9 percentile 3 minute GLCs of Beryllium were below the 3 minute Design Criteria of 0.007 µg/m^3. The predicted 99.9 percentile 3 minute GLCs in the vicinity of Morwell were of the order of 0.001 µg/m^3. The highest predicted 99.9 percentile 3 minute GLCs in the vicinity of Jeeralang Hill was 0.0033 µg/m^3.

Therefore it's expected that since the emissions of berylium from all of the existing brown coal fired power stations and paper mills in the Latrobe Valley result in a maximum 99.9 percentile 3-minute GLC of 0.0033 µg/m^3 (about 47% of the Design Criteria), that the addition of the DGDP to the airshed would not result in the Design Criteria being exceeded.

6.1.3 Cadmium (Cd) and Cadmium Compounds

The concentrations of cadmium that have been measured in Latrobe Valley power station stacks are small from 0.4 to 1.9 µg/m^3. Cadmium concentrations measured in paper mill stacks are also small from 0.1 to 1.7 µg/m^3.

The modelled 99.9 percentile 3 minute Cadmium GLCs in the townships of Moe, Morwell and Traralgon were orders of magnitude below the 3 minute Design Criteria of 0.033 µg/m^3. The highest 99.9 percentile 3 minute GLCs was in the vicinity of Jeeralang Hill at 0.0048 µg/m^3, which is an order of magnitude below the 3 minute Design Criteria.

Therefore it's expected that since the emissions of cadmium from all of the existing brown coal fired power stations and paper mills in the Latrobe Valley result in a maximum 99.9 percentile 3-minute GLC of 0.0048 µg/m^3 (about 15% of the Design Criteria), that the addition of the DGDP to the airshed would not result in the Design Criteria being exceeded.

6.1.4 Chromium VI Compounds

The concentrations of chromium VI that have been measured in Latrobe Valley power station stacks are small from 1.2 to 1.8 µg/m^3.

The modelled 99.9 percentile 3 minute GLCs in the townships of Moe, Morwell and Traralgon were orders of magnitude below the 3 minute Design Criteria of 0.17 µg/m^3. The highest 99.9 percentile 3 minute GLC was in the vicinity of Jeeralang Hill of 0.0045 µg/m^3 and is orders of magnitude below the 3 minute Design Criteria.

Therefore it's expected that since the emissions of chromium VI from all of the existing brown coal fired power stations and paper mills in the Latrobe Valley result in a maximum 99.9 percentile 3-minute GLC of 0.0045 µg/m^3 (about 3% of the Design Criteria), that the addition of the DGDP to the airshed would not result in the Design Criteria being exceeded.

6.1.5 *Nickel (Ni) and Nickel Compounds*

Nickel concentrations that have been measured in Latrobe Valley power station stacks are 4.9 to 7.6 µg/m^3. Nickel concentrations from the paper mill stacks are less than 3 µg/m^3.

The modelling showed that the contributions of the Latrobe Valley Generators and paper mills to predicted 99.9 percentile 3 minute GLCs of Nickel are less than the 3 minute Design Criteria of 0.33 µg/m^3. The predicted 99.9 percentile 3 minute GLCs in the vicinity of Morwell were of the order of 0.006 µg/m^3. The highest predicted 99.9 percentile 3 minute GLC was in the vicinity of Jeeralang Hill at 0.019 µg/m^3.

Therefore it's expected that since the emissions of nickel from all of the existing brown coal fired power stations and paper mills in the Latrobe Valley result in a maximum 99.9 percentile 3-minute GLC of 0.019 µg/m^3 (about 6% of the Design Criteria), that the addition of the DGDP to the airshed would not result in the Design Criteria being exceeded.

6.1.6 *Polychlorinated Dioxins and Furans*

Dioxin and furan concentrations that have been measured in Latrobe Valley power station emissions are 0.000017 to 0.000036 µg/m^3. Dioxin and furan concentrations from the paper mill stacks are less than 0.000007 µg/m^3.

The modelling showed that the contributions of the Latrobe Valley Generators and Australian Paper to predicted 99.9 percentile 3 minute GLCs of Dioxins and Furans are less than the 3 minute Design Criteria of 0.0037 ng/m^3. The predicted 99.9 percentile 3 minute GLCs in the vicinity of Morwell were of the order of 0.000027 ng/m^3. The highest predicted 99.9 percentile 3 minute GLCs in the vicinity of Jeeralang Hill of 0.000091 ng/m^3.

Therefore it's expected that since the emissions of polychlorinated dioxins and furans from all of the existing brown coal fired power stations and paper mills in the Latrobe Valley result in a maximum 99.9 percentile 3-minute GLC of 0.000091 ng/m^3 (about 3% of the Design Criteria), that the addition of the DGDP to the airshed would not result in the Design Criteria being exceeded.

6.1.7 *Polycyclic Aromatic Hydrocarbons (PAHs)*

PAH concentrations that have been measured in Latrobe Valley power station stacks are less than 0.45 µg/m^3. Even before dispersion into the airshed they do not exceed the 3 minute Design Criteria of 0.73 µg/m^3. PAH concentrations from the paper mill stacks are in the range 0.1 to 1 µg/m^3.

The modelling showed that the contributions of the Latrobe Valley Generators and Australian Paper to predicted 99.9 percentile 3 minute GLCs of Dioxins and Furans are less than the 3 minute Design Criteria of 0.73 µg/m^3. The predicted 99.9 percentile 3 minute GLCs in the vicinity of Morwell were of the order of 0.0003 µg/m^3. The highest predicted 99.9 percentile 3 minute GLCs in the vicinity of Jeeralang Hill of 0.0011 µg/m^3.

Therefore it's expected that since the highest 99.9 percentile 3-minute GLCs of 0.0011 µg/m^3 is about 0.02% of the Design Criteria, which includes all of the existing brown coal power stations and paper mills, that the addition of the DGDP to the airshed would not result in the Design Criteria being exceeded.

Therefore it's expected that since the emissions of PAH from all of the existing brown coal fired power stations and paper mills in the Latrobe Valley result in a maximum 99.9 percentile 3-minute GLC of 0.0011 µg/m^3 (about 0.02% of the Design Criteria), that the addition of the DGDP to the airshed would not result in the Design Criteria being exceeded.

6.1.8 ***Class 3 Indicators that are not NPI Reportable Substances***

6.1.8.1 Inorganic Species

Class 3 inorganic species emitted from the Latrobe Valley Generators that are not reported to the NPI are presented below.

Table 6: Inorganic Class 3 Indicators that are not NPI Reportable Substances

Substance	Design Criteria (mg/m^3)	In Stack Concentration (µg/m^3, STP dry)
Radionuclides	ALARA	Levels Low
Respirable Crystalline Silica	0.00033	<65

** see the following for the original reference: Delaney, W. (June 2007). *Ground Level Concentrations of State Environment Protection Policy Class 1, 2, and 3 Indicator Air Emissions in the Latrobe Valley*. HRL Technology, Report HLC/2007/087. Available from: www.powerworks.com.au/HLC2007087.pdf

A previous study discussed the levels of radionuclides found in Latrobe Valley brown coal and ash, which were determined to be very low.[7] Taking into account the low concentrations present as constituents of brown coal and their activity, it is believed that these elements will not pose any significant risk to the ambient air quality for the existing brown coal generators.[7] Therefore, it is expected that the DGDP to the airshed would not result in the Design Criteria being exceeded.

The modelling showed that respirable crystalline silica emissions from power station stacks (based on 2% silica in flyash) resulted in predicted 99.9 percentile 3 minute GLCs in the vicinity of Morwell in the order of 0.049 µg/m^3. The highest predicted 99.9 percentile 3 minute GLC was in the vicinity of Jeeralang Hill at 0.16 µg/m^3 and was below the 3 minute Design Criteria of 0.33 µg/m^3.

Therefore it's expected that since the emissions of respirable crystalline silica from all of the existing brown coal fired power stations and paper mills in the Latrobe Valley result in a maximum 99.9 percentile 3-minute GLC of 0.16 µg/m^3 (about 48% of the Design Criteria), that the addition of the DGDP would not result in the Design Criteria being exceeded.

6.1.8.2 Volatile Organic Compounds (VOCs)

Class 3 VOCs emitted from the Latrobe Valley Generators that are not reported to the NPI are presented below.

Table 7: VOCs that are not NPI Category 2 Substances

Substance	Design Criteria (mg/m^3)	Stack Concentration (µg/m^3, STP dry)
1,2-dichloroethane (ethylene dichloride)	0.13	<2
Benzene	0.053	<2
Trichloroethylene	0.9	<2
Vinyl Chloride	0.043	<2

The modelling results showed that the predicted 99.9 percentile 3 minute GLCs of VOCs in the vicinity of Morwell (Urban) and Jeeralang Hill (Rural) are below their 3 minute Design

Criteria. For example, the predicted 99.9 percentile 3 minute GLC for Benzene in the vicinity of Morwell was 0.0015 μg/m^3 and in the vicinity of Jeeralang Hill of 0.005 μg/m^3 was, which is many orders of magnitude below the design criteria.

Therefore it's expected that since the emissions of these VOCs from all of the existing brown coal fired power stations and paper mills in the Latrobe Valley result in a maximum 99.9 percentile 3-minute GLCs of below their respective Design Criteria, that the addition of the DGDP to the airshed would not result in the Design Criteria being exceeded.

6.1.8.3 Semi-Volatile Organic Compounds (SVOCs)

Class 3 SVOCs emitted from the Latrobe Valley Generators that are not reported to the NPI are presented below.

Table 8: SVOCs that are not NPI Category 2 Substances

Substance	Design Criteria (mg/m^3)	Stack Concentration (μg/m^3, STP dry)
Alpha Chlorinated Toluenes and Benzoyl Chloride	0.017	<0.03
Pentachlorophenol	0.0017	<0.30

The modelling showed that the predicted 99.9 percentile 3 minute GLC for Alpha Chlorinated Toluenes and Benzoyl Chloride in the vicinity of Morwell was 0.00002 μg/m^3 and in the vicinity of Jeeralang Hill was 0.00008 μg/m^3, which is many orders of magnitude below the design criteria of 17 μg/m^3.

The predicted 99.9 percentile 3 minute GLC for Pentachlorophenol in the vicinity of Morwell was 0.0002 μg/m^3 and in the vicinity of Jeeralang Hill was 0.0008 μg/m^3, which is many orders of magnitude below the design criteria of 1.7 μg/m^3.

Therefore it's expected that since the emissions of these SVOCs from all of the existing brown coal fired power stations and paper mills in the Latrobe Valley result in a maximum 99.9 percentile 3-minute GLCs of below their respective Design Criteria, that the addition of the DGDP to the airshed would not result in the Design Criteria being exceeded.

6.1.9 *Summary of Modelling Results for Class 3 Indicators*

Table 9 shows the measured stack concentrations of the Class 3 Indicators that have been measured for Latrobe Valley Generators. The calculated emissions factors from these stack concentrations is presented as well as the NPI emission factors for Victorian brown coal combustion.

Table 9: Measured In-stack Concentrations of Class 3 Indicators for Latrobe Valley Generators[7]

Substance	Stack Concentration* ($\mu g/m^3$ STP dry)	Calculated EF* (kg/tonne)	NPI EF for Vic Brown Coal Combustion (kg/tonne)
Acrolein	Possible By-product		
Acrylonitrile	Unlikely to Occur		
Alpha Chlorinated Toluenes and Benzoyl Chloride	<0.03	1.03E-07	
Arsenic and compounds	0.8 - 12.8	4.41E-05	3.0E-06
Asbestos	Unlikely to Occur		
Benzene	<2	6.90E-06	3.6E-06
Beryllium and Beryllium Compounds	0.78 - 1.3	4.48E-06	1.7E-06
1,3-Butadiene	Unlikely to Occur		
Cadmium and Cadmium Compounds	0.4 - 1.9	6.55E-06	2.5E-06
Chromium VI Compounds	1.2 - 1.8	6.21E-06	6.1E-06
1,2-dichloroethane (ethylene dichloride)	<2	6.90E-06	
Dioxins and Furans (as TCDD I-TEQs)	0.000017 - 0.000036	1.26E-10	8.8E-10
Epichlorohydrin	Unlikely to Occur		
Ethylene Oxide	Unlikely to Occur		
Hydrogen Cyanide	Unlikely to Occur		
MDI (Diphenylmethane diisocyanate)	Unlikely to Occur		
Nickel and Nickel Compounds	4.9 - 7.6	2.62E-05	3.4E-05
PAH (as BaP)	<0.45	1.55E-06	8.8E-07
Pentachlorophenol	<0.30	1.03E-06	
Phosgene	Unlikely to Occur		
Propylene Oxide	Unlikely to Occur		
Radionuclides	Levels Low		
Respirable crystalline silica (inhalded in the form of quartz or crystobalite) (measured as PM2.5)	<65 (based on 2% silica in fly ash)	2.24E-04	
TDI (toluene-2,40diisocyanate and toluene-2,6-diisocyanate)	Unlikely to Occur		
Trichloroethylene	<2	6.90E-06	3.6E-06
Vinyl Chloride	<2	6.90E-06	

* see the following for the original reference: Delaney, W. (June 2007). *Ground Level Concentrations of State Environment Protection Policy Class 1, 2, and 3 Indicator Air Emissions in the Latrobe Valley*. HRL Technology, Report HLC/2007/087. Available from: www.powerworks.com.au/HLC2007087.pdf

The results of the modelling of the 99.9 percentile 3 minute GLCs for the Class 3 Indicators is summarised in Table 10 (based on measured stack concentrations).

Table 10: Predicted 99.9 Percentile GLCs of Class 3 Indicators for Current Latrobe Valley Emitters[7]

Substance	Stack Concentration For Modeling	Urban 99.9 Percential GLC	Rural 99.9 Percential GLC	3-min ave Design Criteria	Urban 99.9 Percential GLC	Rural 99.9 Percential GLC
	($\mu g/m^3$ STP dry)	($\mu g/m^3$)	($\mu g/m^3$)	($\mu g/m^3$)	% of Design Criteria	% of Design Criteria
Acrolein	Possible By-product			0.77		
Acrylonitrile	Unlikely to Occur			14		
Alpha Chlorinated Toluenes and Benzoyl Chloride	<0.03	0.00002	0.00008	17	0.0001%	0.0005%
Arsenic and compounds	<12.8	0.0096	0.032	0.17	5.6%	18.8%
Asbestos	Unlikely to Occur			0.33 fibres/L		
Benzene	<2	0.0015	0.005	53	0.003%	0.009%
Beryllium and Beryllium Compounds	<1.3	0.00098	0.00325	0.007	14.0%	46.4%
1,3-Butadiene	Unlikely to Occur			73		
Cadmium and Cadmium Compounds	<1.9	0.00143	0.00475	0.033	4.3%	14.4%
Chromium VI Compounds	<1.8	0.00135	0.0045	0.17	0.8%	2.6%
1,2-dichloroethane (ethylene dichloride)	<2	0.0015	0.005	130	0.001%	0.004%
Dioxins and Furans (as TCDD I-TEQs)	<0.0000364	2.73E-08	9.10E-08	3.70E-06	0.7%	2.5%
Epichlorohydrin	Unlikely to Occur			25		
Ethylene Oxide	Unlikely to Occur			6		
Hydrogen Cyanide	Unlikely to Occur			370		
MDI (Diphenylmethane diisocyanate)	Unlikely to Occur			0.07		
Nickel and Nickel Compounds	<7.6	0.006	0.019	0.33	1.8%	5.8%
PAH (as BaP)	<0.45	0.0003	0.0011	0.73	0.04%	0.2%
Pentachlorophenol	<0.30	0.0002	0.0008	1.7	0.01%	0.05%
Phosgene	Unlikely to Occur			13		
Propylene Oxide	Unlikely to Occur			160		
Radionuclides	Levels Low			ALARA		
Respirable crystalline silica (inhalded in the form of quartz or crystobalite) (measured as PM2.5)	<65 (based on 2% silica in fly ash)	0.049	0.16	0.33	14.8%	48.5%
TDI (toluene-2,40diisocyanate and toluene-2,6-diisocyanate)	Unlikely to Occur			0.07		
Trichloroethylene	<2	0.002	0.005	900	0.0002%	0.0006%
Vinyl Chloride	<2	0.002	0.005	43	0.005%	0.01%

7. ESTIMATION OF CONCENTRATION OF CLASS 3 POLLUTANTS FROM THE DGDP

The recent air dispersion modelling assessment estimated the GLCs of NO_2 and SO_2 that will result from the operation of the proposed 600 MW DGDP.[1] The modelling was carried in conjunction with other Latrobe Valley sources (i.e. GLCs were determined based on the DGDP being a contributor to the existing Latrobe Valley emission sources). The predicted 1-hour cumulative GLCs of NO_2 and SO_2 resulting from the proposed 600 MW DGDP in conjunction with other emission sources were below the design criteria. The highest 99.9th percentile 1-hour average modelled value for NO_2 is 0.05 ppm (design criteria of 0.10 ppm) and for SO_2 is 0.15 ppm (design criteria of 0.17 ppm).

Estimated GLCs from the proposed 600 MW DGDP resulting from the operation of the DGDP in isolation was not modelled. Previously, air dispersion modelling was conducted for a 550 MW DGDP[8] where the modelling was carried out in isolation and in conjunction with other Latrobe Valley sources (i.e. GLCs were determined based on the DGDP being a stand-alone emission source in the Latrobe Valley and as a contributor to the existing Latrobe Valley emission sources). For the 550 MW DGDP in conjunction with the existing Latrobe Valley emission sources the highest 99.9th percentile 1-hour average modelled value for NO_2 was 0.06 ppm (design criteria of 0.10 ppm) and for SO_2 is 0.15 ppm (design criteria of 0.17 ppm). Therefore, the resulting GLCs were essentially the same as what are predicted in the recent modelling for the 600 MW DGDP in conjunction with the existing Latrobe Valley sources. Validation of the current modelling was done utilising the existing Latrobe Valley sources only and the results indicate that the addition of the DGDP does not have a significant impact on the resulting GLCs of SO_2 and NO_2.

Since the air dispersion modelling for the 600 MW DGDP was not conducted in isolation the results from the previous modelling of the 550 MW DGDP[8] have been used to estimate a dilution factor to apply to the estimated stack emissions from the DGDP to estimate GLCs for Class 3 compounds. The SO_2 dispersion modelling results have been used to estimated a dilution factor to apply to all emissions generated from the DGDP. This has been done in order to provide a rough estimate of the expected maximum GLC of Class 3 Indicators that would occur due to the DGDP.

These estimates are based on the operation of the DGDP in ***isolation*** and assume the following:

- That the NPI and BCIRP emission factors for pulverised brown coal combustion in conventional power stations are representative of the emissions that will result from the DGDP (as stated in Section 5.2 the emissions from gasification plant are generally expected to be lower than for conventional combustion plant); and

- That the modelled dispersion characteristics of SO_2 (on a 1-hour averaging basis) can be applied to the dispersion characteristics of all of the Class 3 Indicators on a 3-minute averaging basis (i.e. apply a uniform dilution factor).

Therefore, these emission estimates provide a *ballpark* estimate of the anticipated GLCs of Class 3 Indicators from the DGDP.

[8] Thornton, D. (December 2009). *Air Quality Modelling Assessment – 550 MW Dual Gas Demonstration Project in Latrobe Valley*. HRL Technology, Report HLC/2009/430

7.1 Concentration in Stack

The emission factors for various Class 3 pollutants published in the National Pollutant Inventory[9] (NPI) were used to estimate the concentration of pollutants from the DGDP stacks. The published emission factors are presented in Table 11. Using the NPI factors and assuming a coal consumption of 3,497,000 t per annum[10], the emission rate (g/s) are determined and also presented in Table 11. Additionally, where NPI emission factors were not available, but an emission factor calculated from the BCIRP work was available, it has been used.

Table 11: Class 3 compounds and NPI emission factors[9] or BCIRP emission factors[7]

Compound	Emission Factor (kg / tonne coal)	Emission Rate* (g/s)
Alpha chlorinated toluenes and benzoyl chloride^	1.07E-07	1.142E-05
Arsenic and compounds	3.00E-06	3.327E-04
Benzene	3.60E-06	3.992E-04
Beryllium and beryllium compounds	1.70E-06	1.885E-04
Cadmium and cadmium compounds	2.50E-06	2.772E-04
Chromium VI compounds	6.10E-06	6.764E-04
1,2-dichloroethane (ethylene dichloride)^	6.90E-06	7.651E-04
Dioxins and Furans (as TCDD I-TEQs)	8.80E-10	9.758E-08
Nickel and nickel compounds	3.40E-05	3.770E-03
PAH (as BaP)	8.00E-07	8.871E-05
Pentachlorophenol^	1.03E-06	1.142E-04
Respirable crystalline silica^	2.24E-04	2.484E-02
Trichloroethylene	3.60E-06	3.992E-04
Vinyl Chloride^	6.90E-06	7.651E-04

* Average over a year, based on an annual coal consumption of 3,497,000 t[10].
^ Indicates the emission factor is from the BCIRP study.

Within the air emissions modelling report by Thornton, the stack dimensions, temperatures, and exit velocities were published[1]; the values are reproduced in Table 12. These stack properties were used to calculate a total volumetric flow rate of 1,081 m^3/s (for gas at 25°C and 101.325kPa).

Table 12: Stack dimensions, temperatures and exit velocities as published in Thornton[1].

	Stack diameter (m)	Stack Temperature (K)	Stack Exit Velocity (m/s)
CCGT 1	5.05	417	33
CCGT 2	5.05	417	33
Char Burner 1	1.37	423	32.8
Char Burner 2	1.37	423	32.8
Air Pre Heater 1	0.43	623	33.1
Air Pre Heater 2	0.43	623	33.1
Pre Dryer 1	1.31	416	33.2
Pre Dryer 2	1.31	416	33.2

[9] Australian Government, Department of the Environment and Heritage; *National Pollutant Inventory Emission Estimation Technique Manual for Fossil Fuel Electric Power Generation Version 2.4*; 15 March 2005
[10] Spreadsheet from HRLD "IDGCC – CO2 emissions V7.xls"

Using the emission rate for the individual compounds (Table 11) and the total volumetric flow rate, the concentration of various compounds at the stack exit can be calculated. The results are presented in Table 13 with a reference stack concentration for comparison. The reference stack concentrations are measured values from stacks in the Latrobe Valley generators and the Australian Paper plant also in the Valley[7].

Table 13: Stack concentrations from the DGDP, averaged over a year.

Compound	Calculated ($\mu g / m^3$)*	Reference[7] ($\mu g / m^3$)*
Alpha chlorinated toluenes and benzoyl chloride#	0.01^	<0.03
Arsenic and compounds	0.3	0.8 < 12.8
Benzene	0.4^	< 2
Beryllium and beryllium compounds	0.17	0.78 - 1.3
Cadmium and cadmium compounds	0.26	0.4 - 1.9
Chromium VI compounds	0.63	1.2 - 1.8
1,2-dichloroethane (ethylene dichloride)#	0.71^	<2
Dioxins and Furans (as TCDD I-TEQs)	0.00009	0.000017 - 0.000036
Nickel and nickel compounds	3.5	4.9 - 7.6
PAH (as BaP)	0.08^	< 0.45
Pentachlorophenol#	0.11^	<0.3
Respirable crystalline silica#	23	<65
Trichloroethylene	0.37^	< 2
Vinyl Chloride#	0.71^	<2

* Gas at 25°C and 101.325kPa.

^ indicates that the estimated stack concentrations are less than the GLC Design Criteria (see Table 1) prior to applying a dilution factor.

# Indicates the calculated emissions were made using the emission factor from the BCIRP study.

As it can be seen in Table 13, the estimated stack concentrations (using NPI and BCIRP emission factors) for almost all compounds from the DGDP are lower than measured stack concentrations from other facilities in the Latrobe Valley, but are generally in the same order of magnitude.

It should be noted that for several compounds the Reference measured stack concentrations are reported as less than the detection limited (e.g. for Benzene the Reference concentration is reported as <2 $\mu g/m^3$). Therefore, the estimation that the calculated emissions of alpha chlorinated toluenes and benzoyl chloride, benzene, 1,2-dichloroethane, PAH, pentachlorophenol, respirable crystalline silica, trichloroethylene, and vinyl chloride from the DGDP are less than the Reference values detection limits is in agreement with stack measurements conducted for the BCIRP study.

The estimated stack concentrations of arsenic, beryllium, cadmium, chromium VI, and nickel are lower than the lower range of Reference stack concentrations measured for the BCIRP study, but are in the same order of magnitude. The emissions of these trace metal compounds will be dependent on the concentration of the metal in the coal, weight fraction of ash in the coal, the particulate emissions from the DGDP, and the proportion of the metal that will volatilise in the gasifier and remain in the gas stream and not condense onto the surface of ash particles (and be removed in the particulate control equipment). Since it is expected that most trace elements should be removed in gasification plant (see Section 5.2) the estimation of the stack emission for the trace metal emissions from the DGDP being slightly lower than the lower end of the Reference values measured for the BCIRP study (which included measurements at conventional brown coal plants - some of which are aging plant) is expected to be reasonable.

The concentration of Dioxins and Furans which is approximately double the upper range of measured stack concentrations in the Valley. This indicates that the NPI emission factor will result in the over estimation of emissions, particularly since the formation of dioxins and furans from gasification processes are expected to be negligible (as discussed in Section 5.2).

It should also be noted, that the stack concentrations of several compounds is less than the GLC Design Criteria prior to applying a dilution factor.

7.2 Dilution Factor

To estimate the ballpark GLCs of compounds resulting from the operation of the 600 MW DGDP, a dilution factor is applied to the estimated concentration at the stack exit. The dilution factor has been estimated from the previous air dispersion modelling for a 550 MW DGDP since resulting GLCs of NO_2 and SO_2 were modelled for the DGDP operating in isolation. A dilution factor has been calculated from the modelled SO_2 concentration from the stack exit and the highest 99.9th percentile GLC.

From Thornton[8], the SO_2 emissions rate from the DGDP is 327 g/s in total, assuming both gasifiers are in use. Based on the total stack volume exit rate, the concentration of SO_2 at the stack exit is calculated to be 0.2636 g/m^3 (gas at 25°C). Thornton[8] determined the ground concentration for SO_2 to be 0.06 ppm (99.9th percentile modelled value), which equates to 1.572×10^{-4} g/m^3 (gas at 25°C). Therefore, the dilution factor would be 1677 (= 0.2636 ÷ 1.572×10^{-4}) for the previous modelling results.

To be conservative a dilution factor of 1000 has been assumed for the calculations made in Section 7.3.

7.3 Concentration at Ground Level

By applying the dilution factor to the Class 3 compounds stack concentration, the ground concentration can be estimated. The results from calculations are presented in Table 14, the design criterion is also presented for comparison.

As can been seen in Table 14, the GLCs of the selected Class 3 compounds is estimated to be typically <1% of the design criterion due to the operation of the 600 MW DGDP in isolation.

Table 14: Estimated concentration of select Class 3 compounds at ground level.

Compound	Ground Concentration		Design Criterion[11] (mg / m³)*
	(mg / m³)*	% of Design Criterion	
Alpha chlorinated toluenes and benzoyl chloride	1.056E-11	0.00006%	0.017
Arsenic and compounds	3.076E-10	0.1809%	0.00017
Benzene	3.691E-10	0.00070%	0.053
Beryllium and beryllium compounds	1.743E-10	2.48999%	0.000007
Cadmium and cadmium compounds	2.563E-10	0.7767%	0.000033
Chromium VI compounds	6.254E-10	0.3679%	0.00017
1,2-dichloroethane (ethylene dichloride)	7.074E-10	0.0005%	0.13
Dioxins and Furans (as TCDD I-TEQs)	9.023E-14	2.4385%	3.7E-09
Nickel and nickel compounds	3.486E-09	1.0564%	0.00033
PAH (as BaP)	8.202E-11	0.0112%	0.00073
Pentachlorophenol	1.056E-10	0.0062%	0.0017
Respirable crystalline silica	2.297E-08	6.9595%	0.00033
Trichloroethylene	3.691E-10	0.00004%	0.9
Vinyl Chloride	7.074E-10	0.00165%	0.043

* Gas at 25°C and 101.325kPa.

8. CONCLUSIONS

In order to make ballpark estimates of the resulting Class 3 pollutants emitted from the proposed 600 MW DGDP several assumptions and approximations had to be made. Typically, power generators and industrial facilities rely on using NPI emission factors to estimate air pollutant emissions from stacks. In HRLT's experience most facilities perform limited stack emissions measurements (e.g. CO, NO_x, SO_2, and Particulate Matter) and power stations in Australia do not generally perform stack sampling for Class 3 Indicators. Rather emissions of Class 3 Indicators are typically determined using the NPI emission factors for Fossil Fuel Electric Power Generation.

However, NPI emission factors are not available for all of the Class 3 Indicators specified in the SEPP. Additionally, not all of the Class 3 Indicators are listed as NPI reportable pollutants. Additionally, there are no NPI emission factors specifically for gasification plant operating on brown coal fuel. Rather, NPI emission factors for brown coal combustion for some Class 3 indicators were available as well as some factors from the BCIRP.

Due to differences between the operation of gasification systems and from conventional combustion a brief literature review was conducted regarding emission studies for pollutants from coal gasification.

There is not a significant amount of publically available information from national or international studies of emissions from integrated gasification combined cycle plant that measured Class 3 Indicators. The general finding of available studies is that IGCC power systems typically achieved the lowest levels of criteria pollutant air emissions (NOx, SOx, CO, PM10) of any coal-fired power plants in the world. Additionally, it was found that

[11] Victoria Government Gazette; *Environment Protection Act 1970*. No. S 240, Friday 21 December 2001; Schedule A, p. 23-24

emissions of trace hazardous air pollutants are extremely low, comparable with those from direct-fired combustion plants that use advanced emission control technologies.

HRLT previously conducted air dispersion modelling of Class 1, Class 2, and Class 3 Indicators in the Latrobe Valley emitted from the existing brown coal fired power stations and paper mills.[7] The ground level concentrations (GLCs) of the Class 3 Indicators in the Latrobe Valley predicted from the air dispersion modelling were compared with the SEPP (Air Quality Management) Design Criteria and it was found that all of the Class 3 Indicators modelled were below the Design Criteria and were typically significantly below the Design Criteria GLCs.

Recent modelling of the 600 MW DGDP indicated that the DGDP should not have a significant impact on the resulting GLCs of NO_2 and SO_2. Since it's expected that the emissions of trace hazardous air pollutants from IGCC plant are low (comparable with those from direct-fired combustion plants that use advanced emission control technologies) and that previous modelling of certain Class 3 indicators for the existing Latrobe Valley brown coal fired power stations and paper mills resulted in GLCs that were typically significantly below the Design Criteria GLCs, it is expected that the addition of the 600 MW DGDP to the air shed should not significantly impact the GLCs of Class 3 indicators in the Latrobe Valley and should not result in the Design Criteria being exceeded.

Ballpark estimates of Class 3 stack emissions from the DGDP were determined assuming that the NPI and BCIRP emission factors for pulverised brown coal combustion in conventional power stations are representative of the emissions that will result from the DGDP. The emissions estimates for several of the Class 3 Indicators indicate that the in-stack concentrations are lower that the GLC Design Criteria specified in the SEPP prior to applying a dilution factor. This supports the theory that the addition of the 600 MW DGDP to the air shed should not significantly impact the GLCs of Class 3 indicators in the Latrobe Valley and should not result in the Design Criteria being exceeded.