

Dual Gas Demonstration Project

Statement of David Walton

**Prepared with respect to VCAT Proceedings P1816/2011; P1818/2011;
P1820/2011; P1822/2011; P1829/2011; P1846/2011**

3 October 2011

Introduction

The Dual Gas Demonstration Project (“DGDP”) is a 600MW Integrated Drying and Gasification Combined Cycle (“IDGCC”) power generation project proposed by Dual Gas Pty Ltd (“Dual Gas”).

This report has been prepared in relation to the various applications for review made with respect to the DGDP, including those applications for review made by Dual Gas Pty Ltd. It comprises the following six sections:

Section 1 sets out the author’s relevant qualifications and expertise.

Section 2 contains a summary of the report.

Section 3 describes the differences between the proposed 600MW facility and the approved 300MW facility, including the differences in cost, efficiencies and operation.

Section 4 addresses the requirement to provide sulphur capture equipment at the commencement of the DGDP, as opposed to an integrated sulphur and carbon capture capability in the future, including costs and feasibility.

Section 5 considers Australia’s current market for power generation – the National Electricity Market (“NEM”) – and the role that the DGDP will play within that market.

Section 6 examines the global potential for the IDGCC technology.

1. Relevant Qualifications and Expertise

1.1. Formal Qualifications

ACMA - 1984 qualified and registered as an Associate with the Chartered Institute of Management Accountants in the UK (CIMA).

FCMA - 1989 gained Fellowship status with the UK CIMA.

1.2. Industry Experience

My CV is provided as Appendix D to this statement. It provides a comprehensive account of my professional experience.

In broad terms, for a period of in excess of 20 years, I have acted in a number of capacities – including Chief Executive Officer ("CEO"), Chief Financial Officer ("CFO"), General Manager, and Financial Manager – in various private sector organisations operating within the energy, utilities and telecommunications industries. I have particular expertise in the power generation industry having:

- been the CEO of a substantial portfolio of power generation and heating businesses;
- been involved in power station project developments and divestments; and
- been a Station Manager of a 118MW power station.

1.3. Dual Gas

In September 2010 I was retained under a contracting role by Dual Gas as the CFO of Dual Gas. My responsibilities to this point in time, however, have been outside those of a traditional CFO and have included the management of wider development and commercial requirements for the DGDP (such as project evaluation, risks and mitigation, planning, optimisation, and due diligence preparation).

2. Summary

2.1. Integrated Drying and Gasification (“IDG”) Capacity and Configuration - 600MW / 300MW

The capital investment cost for power generation facilities is generally presented as \$/kW installed (referenced for the purposes of this report as the “cost of capacity installed”) which is ultimately reflected in the unit cost of electricity generated (\$/MWh).

Whilst the absolute cost for the proposed 600MW facility will be significantly greater than the approved 300MW, the cost of capacity installed (\$/kW) of the approved 300MW facility is estimated to be approximately 23% greater than that for the proposed 600MW facility.

Further, there are additional efficiency and operational benefits offered by the proposed 600MW facility (which implements a “2 plus 1” Combined Cycle Gas Turbine (“CCGT”) configuration), as compared to the approved 300MW facility (which implements a “1 plus 1” CCGT configuration). Whilst not valued as part of the increased cost of capacity installed (\$/kW), the operation and maintenance of the approved CCGT configuration, along with the refurbishment of hot gas path parts and the provision of spare parts, will all result in a higher unit cost of power generated in the case of the approved 300MW facility (comparable to the proposed 600MW facility).

This would translate to an increase in the unit cost of power generated by the respective facilities of approximately 12% to 20%.

The increased cost of capacity installed of the approved 300MW facility, together with the additional cost of sulphur capture (set out in paragraph 2.2), results in a total increased cost of capacity installed in excess of 30%.

2.2. Installation of 90% Sulphur Capture

Sulphur capture will increase the overall capital investment in the DGDP by an estimate \$120 million for a 300MW facility (with one gasifier) and by an estimated \$195 million for a 600MW facility (with two gasifiers). This equates to an increase in the cost of capacity installed of \$400/kW for a 300MW facility and an increase in the cost of capacity installed of \$325/kW for a 600MW facility, an increase of 11%.

This additional cost will significantly reduce the commercial viability of the DGDP at either the proposed 600MW capacity or the approved 300MW capacity.

2.3. The National Electricity Market (“NEM”)

The DGDP will be required to register with Australian Energy Market Operator (“AEMO”) as a generator within the NEM alongside other generation facilities (including renewables).

Assuming that current AEMO rules and practices remain in place, renewable generation that is taken by AEMO as ‘non-scheduled’ will be dispatched ahead of ‘scheduled’ generation.

The DGDP will be required to register as a 'scheduled' generating unit which will require the DGDP to offer MW and prices to be scheduled and dispatched by AEMO as part of a generation merit order, optimising availability (MW) and prices (\$/MWh). The scheduling and merit order will result in AEMO economically dispatching generation to meet and balance real time market demand within the NEM.

Under this system the DGDP only has the potential to displace other scheduled generation (such as that from existing coal fired power stations within the Latrobe Valley). It cannot displace 'non-scheduled' renewable generation.

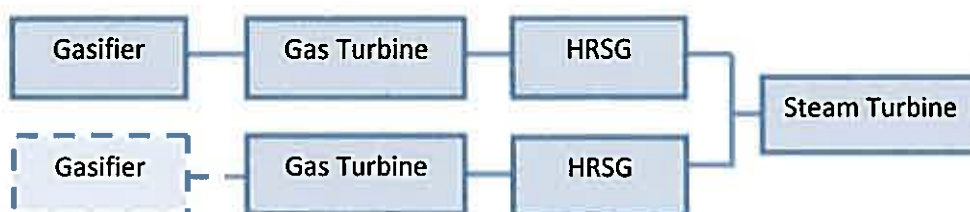
2.4. Global Market for IDG and IDGCC

The IDGCC technology has the potential to be applied in power generation in any country with reserves of low rank coal, which include China, India, and Eastern Europe. After IDG technology has converted coal into syngas, the syngas can be further refined to produce other products, such as liquids, chemicals and fertilizers (CTX). There is therefore significant commercial potential and value for IDG technology beyond power generation.

3. IDGCC Capacity and Configuration

3.1. The Proposed and Approved CCGT Modular Configuration

The generally accepted most beneficial application of gas turbine combined cycle power generation is in the modular form described as “2 plus 1” being two of the same gas turbines (“GT”) into one steam turbine (“ST”). The figure below shows the configuration as proposed by Dual Gas in its WA Application, with the staged deferral of the second gasifier.¹



Specifically, in respect of the combined cycle technology, this modular arrangement optimises efficiency and operational benefits in the following ways:

- One GT can be planned out of operation and allow the facility to continue at part load utilising the other GT, thereby offering operational flexibility.
- Only a ST break-down or its direct support equipment will cause a station shutdown. GT break-downs will be independent of each other.
- Critical and expensive refurbishment of the GT hot gas path parts can be optimised in rotation reducing refurbishment times and providing maintenance flexibility thereby reducing the most significant maintenance cost of a CCGT.
- The GTs and ST can share a common generator transformer, which thereby requires only one critical spare part to be held.
- A single ST provides greater efficiency (compared with 2 smaller STs), with the typical efficiency differential estimated to be approximately 0.3 or 0.4%. There would be a commensurate differential in emissions produced by the plant.

The “2 plus 1” configuration for larger capacity facilities also reduces construction risk in that all is not lost if construction issues arise, such as factory failure, marine shipping losses, construction faults or delays. In the “2 plus 1” configuration such issues can be addressed or reconsidered earlier for the second GT module.

It is partly for these reasons, as discussed in further detail in part 3.4 below, that the proposed 600MW facility would provide a lower cost of capacity installed and a lower unit cost of electricity generated than the approved 300MW facility.

The facility as approved in the Works Approval (“WA”) would result in a “1 plus 1” configuration, in the form shown in the figure below, and will not have the benefits detailed above.

¹ HRSG is Heat Recovery Steam Generator.



Design and construction of a “1 plus 1” configuration limited to a 300MW capacity would require installation of a ST to meet the 300MW capacity alone, which in turn would:

- restrict the ability to move to a larger “2 plus 1” configuration at a later date insofar as the capacity of the ST would be fixed;
- result in lower efficiency from a smaller ST;
- increase costs, from a higher cost of capacity installed, and disproportionate operating and maintenance costs relative to the ST capacity.

Furthermore, the approved configuration would:

- require a re-design of the proposed 600MW facility to accommodate the removal of 300MW of capacity with all the associated support plant; and
- result in an increase in the cost of capacity installed and an increase in the unit cost of electricity generated (as described in further detail in part 3.2 below).

3.2. Relative Costs of 600MW and 300MW

The installation cost for power generation is a critical factor for project viability. As noted above, the capital investment cost is usually presented and estimated in terms of \$/kW installed (cost of capacity installed).

For commercial reasons Dual Gas is not willing to disclose the costs of the IDG plant or the integrated IDGCC plant. The Treasury Report entitled “Carbon Pricing and Australia’s Electricity Markets” prepared by SKM/MMA (dated July 2011) does, however, provide an indication of the differential costs of the proposed 600MW facility and approved 300MW facility. That report details the estimated costs of various technologies including small, medium and large CCGT plants.

Appendices A (i) and (ii) to this statement sets out the estimated costs of the various technologies as contained in the SKM/MMA Treasury Report.

I have analysed the engineering, procurement and construction contract (“EPC contract”) and tendering documentation for the 600MW DGDP proposed by Dual Gas, to ascertain the relative costs as between the 600MW DGDP and a potential 300MW facility. The EPC contract and tendering documentation are confidential, containing commercially sensitive information, and Dual Gas is not willing to disclose these documents.

I have also referred to the Treasury Report and the results set out in Appendices A(i) and (ii) to this statement, specifically to the relative costs of ‘Small’, ‘Medium’ and ‘Large’ CCGT \$/kW installed and to the cost of ‘Brown Coal Supercritical’ at \$2900/kW installed.

IDGCC technology \$/kW installed will be materially less than the \$2900/kW indicated by SKM/MMA (in Appendix A(i)) and the \$3193/kW indicated by ROAM Consulting (in Appendix A(ii)), being the lowest cost technology for brown coal.

In light of the above, I am of the view that an estimate of the extent to which the approved 300MW IDGCC facility would result in an increase in the cost of capacity installed (above the proposed 600MW IDGCC facility), would be approximately 23%. This would translate to an increase in the unit cost of electricity generated of between 12% to 20% when considering the effect of a changed configuration described in section 3.1.

3.3. E Class v F Class Turbines

All GTs are generally 'off-the-shelf' designs from original equipment manufacturers ("OEM") such as Alstom, GE, MHI, Siemens and Ansaldo (and more) and require minimal design adjustments to cater for local gas constitution and characteristics. OEMs seek to control certainty of the build quality, GT life, and maintenance knowledge, to maximise sales values (which means that design consistency and operational history are critical).

The DGDP requires GT(s) capable of burning syngas derived from brown coal which has a completely different constitution and different characteristics to natural gas and to other sources of syngas. Important differences include energy content and water content. These differences affect the resulting volume throughputs to a GT. Accordingly, a GT capable of burning syngas requires considerable re-design. Dual Gas was ultimately offered redesign and subsequent performance guarantees only in respect of an E Class turbine. In my experience, it is likely that this restricted offer is based on:

- The available knowledge from other similar E Class turbines having undergone re-design for other 'out of spec' facilities.
- Reluctance to modify latest technology which still has 'new product life'.
- Reluctance to invest in re-design expenditure required to provide OEM performance guarantees for MW output and heat rate, a pre-requisite for successful project debt and /or equity funding.
- Willingness to invest in modification of an E Class turbine to extend product life and potential.

Manufacturers of more efficient F Class GTs would need to see a potential market for the redesign of their GTs to operate on low energy syngas in order to incur the cost and expense. I do not believe that a single GT operating on syngas technology would be sufficient to justify this expenditure. There would need to be clear evidence of a growth in the global market for IDGCC technology in order to provide the commercial incentive to develop the more efficient GTs capable of operating on syngas derived from low rank or brown coal. There is no indication of when OEMs might move into this area for F Class GTs.

To my knowledge, the DGDP is the only project with the requirement for GT fuel and handling and combustion modifications for low energy syngas from low rank coal.

Even if more efficient GTs were potentially available to operate on low energy syngas in the future, there would still be a number of impediments to the adoption of anything other than an E Class GT for any second stage of development contemplated with respect to the DGDP. This is because:

- An F Class GT would not secure the benefits detailed in section 3.1.
- An F Class GT would not be the same MW capacity as the existing E Class GT, and would therefore require a different ST for the combined cycle operation. Consequently, the mismatch of plant economies would fall across the ST (as well as the GT) once again increasing plant operational risk and costs.
- The IDG gasifier has been designed to be compatible with around 170MW of GT power output (300MW with combined cycle ST). Any revised GT output would not be applicable to the current gasification design and established construction. Accommodating this revised GT integration would once again increase operational risk and costs around a gasifier and also re-introduce some IDG technology risks.

3.4. Alteration of the Approved Configuration

The proposed 600MW facility contemplates a two-stage construction:

- Stage 1 : construction of the “2 plus 1” combined cycle power plant (the 2 GTs and the 1 ST) and the first IDG Gasifier;
- Stage 2 : construction of the second IDG Gasifier (when the first IDG Gasifier has been operated and proven to an acceptable degree of success, together with appropriate modifications to the GT).

As noted in section 3.1 above, the approved 300MW facility would adopt a different configuration to that which was proposed. In particular, the approved 300MW facility would adopt a “1 plus 1” configuration. This facility would be constructed in a single phase and would incorporate a ST to meet the 300MW capacity.²

Under this configuration, if the IDGCC technology proves successful and permission is later sought to add a further 300MW of capacity to the DGDP, it would not be feasible to convert the existing plant into a “2 plus 1” configuration. This would in essence require the replacement of the existing ST and associated plant (which would be configured to meet the 300MW capacity) with a new ST and associated plant (which is configured to meet the 600MW capacity). Instead, it would be necessary to construct the further 300MW of capacity in a stand-alone “1 plus 1” configuration.

It is estimated that the cost of capacity installed of two complete “1 plus 1” stages of 300MW would be about 32% more than the cost of capacity installed of a “2 plus 1” configuration as per the proposed 600MW facility.

² While it would be technically possible to install at the outset a ST to meet a future enhanced capacity, such as 600MW, the ST would operate at a part-load capacity and efficiency until such time as the capacity of the plant was enhanced. Running a ST at a relatively low load factor would be extremely inefficient.

4. Sulphur Capture

Firstly, it should be noted that sulphur capture was never contemplated as a requirement or potential requirement for the DGDP since the fuel source is considered to have extremely low sulphur content. Subsequent discussion on the requirement and associated costs are therefore estimates, largely based on estimates by HRL Developments Pty Ltd prepared whilst investigating pre-combustion capture of CO₂ from syngas, which also requires the removal of sulphur compounds.

4.1. Carbon Capture (and Integrated Sulphur Capture) Timeline

Carbon capture and sulphur capture require the same or substantially similar equipment and processes and for this reason are ideally captured utilising common plant installed at the same time.

Globally there is a foreseen requirement for 'carbon capture' to be implemented for power generation facilities using coal and eventually gas. The Federal and Victorian Governments have also foreseen this requirement and are assessing Carbon Capture and Storage ("CCS") feasibility with respective 'Flagship' programs and the 'CarbonNet' project. The CarbonNet project requires captured carbon to test and implement CCS by around 2020.

Carbon capture can be either pre- or post-combustion. Post-combustion technologies are currently being explored at non-commercial scales. As such the cost, effectiveness, and commercial viability of the technology is unknown. Pre-combustion technologies, on the other hand, are available and in operation at commercial scales in the oil and gas industries. Unlike other coal fired power stations, a pre-combustion process is technically available and proven to capture carbon and sulphur from the IDGCC process.

The DGDP is ideally suited to demonstrate carbon capture technology in the future and within the 2020 timeframe envisaged by the CarbonNet project.

Without the infrastructure in place to transport, inject and store carbon, the installation of carbon capture technology would be premature.

The potential for CCS to be implemented in Victoria is being advanced at State and Commonwealth levels. See, for instance, the information relating to CCS technology on the Department of Primary Industries website.

4.2. The Cost and Other Effects of Sulphur Capture in advance of Carbon Capture

Capital Costs

As noted above, an integrated system to capture sulphur and carbon at the same time is less expensive than installing sulphur and carbon capture plant separately. The installation of an integrated system is only \$20m greater than installing carbon capture by itself (that is, excluding the plant and equipment required for integrated sulphur capture).

Engineering, design and construction of a system exclusively for sulphur capture is estimated at \$120m for a 300MW facility and at \$195 for a 600MW facility.

The difference in cost between installing an integrated carbon and sulphur capture system, and installing separate carbon and separate sulphur capture plant, is estimated to be \$100m.

The comparative differential in cost is due to the cooling, de-humidification, capture volumes and re-humidification of the syngas and relative actual volumes of sulphur and carbon content of syngas.

The exact costs of an integrated sulphur and carbon capture plant is commercially sensitive and Dual Gas is not willing to disclose this figure.

It is estimated that the cost of capacity installed for the IDGCC technology (integrated drying) will be materially less than the \$2900/kW indicated by SKM/MMA (in Appendix A(i)) and the \$3193/kW indicated by ROAM Consulting (in Appendix A(ii)), again being the lowest cost technology for brown coal.

As a consequence, it is estimated that the impact of the additional \$120m for a 300MW facility in capital attributable to the sulphur capture will result in an increase of \$400/kW installed. It is estimated that the impact of the additional \$195m for a 600MW facility results in an increase of \$325/kW installed. This is around 11% on the cost of capacity installed of the proposed 600MW and a 300MW facility.

Operating Costs

The operating cost of additional sulphur capture equipment will comprise the parasitic load (the electricity used internally), consumables, maintenance, and carbon costs. It is estimated that this cost will be between \$1m and \$5m each year.

Additional Emissions

Emissions of CO₂-e attributable to the sulphur capture equipment, based on a parasitic load of 1MW, equates to approximately 7000 tonnes per year.

Demonstration of IDG technology

Installation of sulphur capture plant would be premature prior to the proven operation of the IDG Gasifier to an acceptable degree of success.

Other Power Stations

To the best of my knowledge no other power generation facility currently operating in Victoria or Australia currently utilises sulphur capture technologies.

5. The National Electricity Market (NEM)

Australia currently has two distinct types of electricity markets, which are separated commercially and physically.

Firstly, Western Australia and the Northern Territory are regions, each of which has an independent electricity market. Regulations and operations have been developed for each of these regions to meet the specific conditions of their respective power requirements. This report does not cover the commercial consideration of these independent electricity ‘markets’.

Secondly, the National Electricity Market (“NEM”) is an inter-connected wholesale electricity market, which allows for the supply and purchase of electricity along the eastern seaboard, including Queensland, New South Wales (including the ACT), Victoria, South Australia and Tasmania. These regions are inter-connected to allow for the flow of power between regions depending on pricing, which is driven by regional demand and supply and interconnection capabilities at a particular point in time. This ‘market’ is managed and operated by the Australian Energy Market Operator (“AEMO”) and regulated by the Australian Energy Regulator (“AER”).

5.1. NEM Commercial Operation

In general terms, generators submit offers to AEMO to supply certain amounts of electricity at particular prices every five minutes. Generators will make their offers to the market to capture a gross margin for each MWh based on:

- The cost of production per MWh derived from:
 - fuel/energy cost and the conversion efficiency;
 - operation and maintenance cost of the technology.
- The volume of MW available from the technology.
- The contribution required to cover:
 - fixed costs; and
 - returns to debt and / or equity providers.

In making their offers, generators will also consider their target market, which can be large volumes with associated low price through to high price - **base-load**, or relatively small volumes with associated high prices - **peaking**. Each target market has its respective risk and commercial value and can only be captured with the appropriate technology, energy source (fuel), and business model. Appendix B provides a full list of thermal generation facilities in the NEM, comprising all base-load and peaking capacities.

Using the offers made by generators, AEMO balances demand and supply in each of the regions, and therefore the NEM. It does this by managing the advance (day-ahead) scheduling and subsequent dispatch of generation facilities using a merit-order ranking of generators, which is based on the price and volume of electricity offered by generators for a MW/hr (\$/MWh) for a particular trading interval. The last offer dispatched to meet the demand in real time for a trading interval produces a spot price in each region that represents the marginal price of producing the next increment of electricity for the region for the relevant trading interval.

Supply and demand are balanced by AEMO using a process that attempts to optimise electricity traded based on various parameters, particularly commercial considerations and system capabilities. AEMO progressively balances generators' supply offers with the demand forecast and then the actual real-time demand by considering:

Scheduling considerations

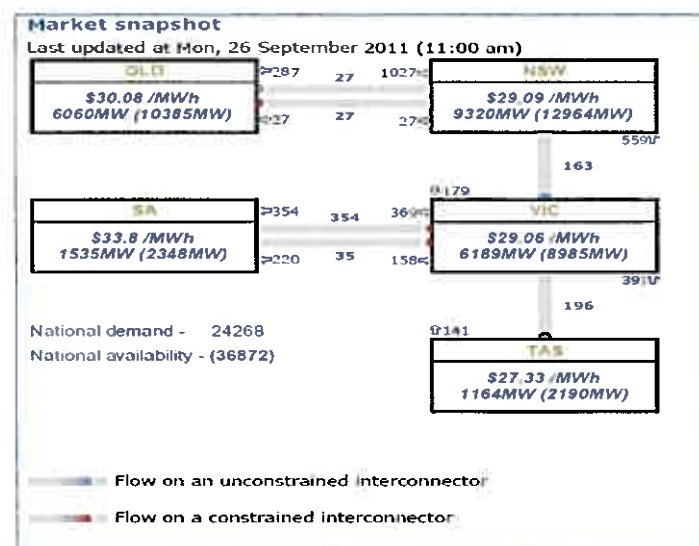
- Advance availability of supply from each generation unit connected to the system, which takes into account planned outages and the price and volume at which power is offered.
- Supply from non-scheduled or semi-scheduled generation such as wind and solar, which generally do not participate in the central dispatch process.
- Forecast demand for power.

Dispatch considerations

- Changes from the assumptions upon which the dispatch schedule was originally established.
- Unexpected increases in demand such as spikes resulting from hot or cold weather fronts or even resulting from significant 'social events'.
- Forced outages caused by generator plant breakdowns or restrictions or transmission/distribution system failures.
- Valid price changes made by generators.

All this is done with 5 minute pricing signals, which are used to generate half hour price averages for every day.

AEMO and AER provide regular data on the market for analysis. In particular, the "Market Snapshot" provides an insight into the configuration of the NEM, the regions, interconnection, demand and supply and the resulting competitive pricing at a particular point in time. An example of such a snapshot is set out below.



5.2. The Potential for the DGDP to Displace Renewable Generation

The DGDP must register as a 'scheduled' generating unit, which will require DGDP to offer MW and prices to be scheduled and dispatched by AEMO according to the generation merit order ranking, based on output availability (MW) and prices (\$/MWh) as described earlier.

Certain renewable electricity generation facilities, particularly large-scale wind and solar, will qualify to be registered with AEMO. These types of renewable energy facilities are, in the main, registered as 'non-scheduled' or 'semi-scheduled', to account for their intermittent and unpredictable generation. AEMO takes the real time actual output for non-scheduled or semi-scheduled electricity generation as it is available and ahead of 'scheduled' generation, which is dispatched according to the merit order ranking. Consequently, based on current market rules and practices, the DGDP will not displace non-scheduled and semi-scheduled renewables generation.

The DGDP has the potential to displace other scheduled generation with its offer of MW and \$/MWh based on low cost brown coal and a reduced carbon intensity (tCO₂-e/MWh) resulting from the use of the IDGCC technology. In particular, the expectation is that the DGDP will displace generators that have a combination of high costs (largely driven by fuel type) and relatively high burden to pay the carbon price under proposed carbon price legislation.

5.3. Technology and the Market.

Base load v Peaking Power.

Base load power is the minimum amount of power required to meet minimum demands based on reasonable expectations of customer requirements. Peaking power plants generally run only when there is relatively high demand, known as peak demand, for electricity.

In the NEM, base load plants are generally thermal plants using fossil fuels, mainly brown and black coal. These are currently the lowest cost plants, which helps to secure their position in the merit order. They provide power throughout off-peak and peak times of the day and seasons to provide base load requirements as well as demand that goes beyond these base load requirements.

The nature of renewables generation capability is that it could not guarantee availability or output to match either the constant base load demand or the peak demand in all circumstances.

Natural gas generation has, up until this point in time, predominantly operated at mid-merit order and to provide peaking electricity generation.

To my knowledge, in Victoria, as yet, there have been no gas generators that generate base load electricity.

New Entrant Technology Costs

Appendix C gives an indicative cost of power (long run marginal costs) for new coal and gas generation entrants into the NEM ranging from \$44 to \$65/MWh. Along with the long run marginal costs, Appendix C also shows the expected new entrant type and fuel costs for various regions in the NEM. In my understanding, it would not be viable for these new entrants to provide base load based on current market prices.

Recently developed new natural gas power plants, for instance Mortlake, have chosen to operate as peaking plants and are constructed initially as open cycle gas turbines (OCGT). OCGT plant has a lower capital investment cost (\$/kW installed) and operates at a significantly higher fuel or energy price. The recent new gas power entrants into the Victorian market have been peaking plants, designed using specific technology and business models to extract generation value (or protect retail wholesale purchases) from the extremes of the peaking market only. These peaking plants will not cover base load demand.

6. IDGCC Potential in Australia and Globally

The IDGCC and gasification technology has potential for expansion in the Latrobe Valley and in any other location in which commercial quantities of low rank or brown coal are situated. HRL has developed the unique technology specifically around brown coal as compared to other gasification technologies which operate on oil, pet-coke and black coal fuel sources.

Once brown coal is gasified and the energy is in the form of syngas there is potential not only for higher efficiency power generation but also the creation of other products such as liquids, chemicals and fertilisers (CTX) and hydrogen.

Low rank and brown coals are abundant in China, India, and Eastern Europe which are the growth economies of the world.

Appendix A**i. Generating Technologies****The Treasury; Carbon Pricing and Australia's Electricity Markets July 2011 – SKM MMA**

GENERATING TECHNOLOGY	BASE CAPITAL COST (\$/KW)	THERMAL EFFICIENCY (%)	FIXED O&M COSTS (\$/KW/YEAR)
Black Coal Options			
Supercritical coal (dry-cooling)	2,357	40	30
Ultra-supercritical coal (wet cooled)	2,235	41	30
IGCC	3,643	46	45
IGCC with CC	5,418	36	50
Ultra-supercritical with CC and oxy-firing	5,676	30	40
USC with post-combustion capture (wet cooled)	3,828	31	40
Brown Coal Options			
Supercritical coal with drying	2,900	31	36
Supercritical coal	2,900	29	36
Ultra supercritical coal with drying	3,000	32	36
IGCC with drying	6,601	35	50
IGCC with drying and CC	9,816	26	60
Natural gas options			
CCGT – small	1,850	43	30
CCGT – medium	1,400	46	25
CCGT – large	1,300	51	18
Cogeneration (large)	1,900	69	25
CCGT with CC (wet cooled)	2,755	44	45
Renewable energy options			
Wind	2,400		40
Biomass - Steam (wood waste used)	6,382	25	60
Biomass - Gasification (wood waste used)	5,361	25	60
Concentrated Solar thermal plant - without storage	6,500		50
Concentrated Solar thermal plant - with storage	9,500		60
Geothermal – HSA	6,500	28	50
Geothermal - Hot Rocks	7,000	26	50
Concentrating PV	6,175		45
Hydro	3,500		35

ii. Generating Technologies
 The Treasury; Projections of Electricity Generation in Australia August 2011 – ROAM Consulting

Table A.4 – New Entrant Technical and Financial Assumptions

Technology	Financial Life	Auxiliary Load	Capital Cost 2010 \$/kW installed	Capital Cost Deescalator 2015-2030	Heat Rate 2010 (HHV as generated)	Heat Rate 2020 (HHV as Generated)	Heat Rate 2030 (HHV as Generated)	Variable O&M Costs (\$/MWh)	Fixed O&M Costs (\$/MW p.a.)
Supercritical Black Coal	30yrs	9.8%	\$ 2,393	0.7% p.a.	42.1%	45.8%	53.3%	\$ 4.60	\$ 33,000
Supercritical Black Coal with CCS	30yrs	23.3%	\$ 4,017	0.9% p.a.	37.0%	41.4%	50.1%	\$ 15.70	\$ 55,000
Supercritical Brown Coal	30yrs	10.3%	\$ 3,193	0.7% p.a.	38.8%	43.4%	52.5%	\$ 5.10	\$ 41,000
Supercritical Brown Coal with CCS	30yrs	23.9%	\$ 5,008	0.9% p.a.	33.5%	38.9%	49.6%	\$ 16.40	\$ 67,000
Combined Cycle Gas Turbine	30yrs	2.9%	\$ 1,224	1.0% p.a.	51.0%	53.8%	59.3%	\$ 2.00	\$ 14,000
Combined Cycle Gas Turbine with CCS	30yrs	15.4%	\$ 2,110	1.3% p.a.	48.7%	51.9%	58.2%	\$ 4.24	\$ 25,000
Open Cycle Gas Turbine	30yrs	1.0%	\$ 881	0.8% p.a.	48.7%	35.8%	40.4%	\$ 2.50	\$ 9,000
Solar Thermal – Central Receiver	30yrs	10.0%	\$ 5,211	2.3% p.a.	100.0%	100.0%	100.0%	\$ 0.00	\$ 73,000
Solar Thermal – Central Receiver with 6hrs storage	30yrs	10.0%	\$ 3,669	2.7% p.a.	100.0%	100.0%	100.0%	\$ 0.00	\$ 55,000
Wind Turbines	30yrs	0.0%	\$ 2,581	1.3% p.a.	100.0%	100.0%	100.0%	\$ 0.00	\$ 39,000
Geothermal – Enhanced Geothermal System	30yrs	15.0%	\$ 6,167	0.4% p.a.	100.0%	100.0%	100.0%	\$ 0.00	\$ 187,500
Geothermal – Hot Sedimentary Aquifers	30yrs	15.0%	\$ 5,902	0.7% p.a.	100.0%	100.0%	100.0%	\$ 0.00	\$ 125,000
Biomass	30yrs	0.0%	\$ 4,472	0.0% p.a.	30.1%	30.1%	30.1%	\$ 2.25	\$ 40,000

Appendix B – Thermal Plant in the NEM Treasury Report July 2011 Carbon Pricing and Australia’s Electricity Markets, SKM/MMA

PLANT	NO UNITS	TOTAL SENT OUT CAPACITY	SCHEDULED MAINTENANCE (WEEKS PA)	EFFECTIVE FORCED OUTAGE RATE	AVAILABLE CAPACITY FACTOR	FULL LOAD HEAT RATE (SENT OUT)	VARIABLE O&M COST \$/MWH (SENT OUT)	VARIABLE FUEL COST \$/GJ	TOTAL VARIABLE COST \$/MWH (SENT OUT)
Victoria									
AGL	4	159.2	4.0	9%	84.0%	13.50	\$2.77	\$4.07	\$57.69
Anglesea	1	146.3	1.0	2%	96.6%	13.00	\$1.38	\$0.14	\$3.23
Bairnsdale	2	91.5	3.0	1%	93.3%	11.50	\$4.15	\$4.19	\$52.42
Energy Bkr	5	150.9	5.0	4%	86.8%	21.25	\$2.77	\$0.64	\$16.33
Hazelwood	8	1472.0	4.0	9%	84.0%	13.30	\$2.77	\$0.64	\$11.26
Jeeralang A	4	230.8	2.1	1%	95.0%	13.75	\$8.31	\$3.97	\$62.83
Jeeralang B	3	253.7	2.1	1%	95.0%	12.85	\$8.31	\$3.97	\$59.26
Laverton	2	338.3	2.0	2%	93.9%	11.55	\$4.15	\$4.07	\$51.14
Loy Yang A	4	2043.0	2.5	4%	91.9%	11.58	\$1.10	\$0.48	\$6.72
Loy Yang B	2	966.0	2.5	3%	92.3%	11.70	\$1.10	\$0.48	\$6.78
Valley Power	6	313.4	2.1	1%	95.0%	13.75	\$8.31	\$3.97	\$62.83
Yallourn W	4	1368.0	3.0	6%	88.6%	12.91	\$1.38	\$0.49	\$7.80
Newport	1	484.5	2.2	3%	93.0%	10.33	\$2.77	\$4.07	\$44.80
Mortlake OCGT	2	550.2	2.5	2%	93.0%	10.60	\$3.52	\$3.60	\$41.63
HRL	committed	493.0	2.0	20%	76.9%	7.17	\$3.35	\$0.48	\$6.79

DJ Walton Statement – VCAT

PLANT	NO UNITS	TOTAL SENT OUT CAPACITY	SCHEDULED MAINTENANCE (WEEKS PA)	EFFECTIVE FORCED OUTAGE RATE	AVAILABLE CAPACITY FACTOR	FULL LOAD HEAT RATE (SENT OUT)	VARIABLE O&M COST \$/MWH (SENT OUT)	VARIABLE FUEL COST \$/GJ	TOTAL VARIABLE COST \$/MWH (SENT OUT)
South Australia									
Angaston	1	48.8	0.0	0%	99.5%	9.00	\$11.88	\$21.03	\$201.23
Dry Creek	3	147.3	4.0	3%	89.1%	17.00	\$8.31	\$9.92	\$177.09
Hallett	5	210.1	4.0	5%	87.9%	12.00	\$9.48	\$21.03	\$261.94
Ladbroke Grove	2	85.6	3.0	2%	92.1%	10.00	\$6.93	\$4.70	\$53.95
Minilaro 1	1	89.6	4.0	5%	88.1%	16.00	\$8.31	\$9.92	\$167.16
Northern	2	505.1	2.8	2%	92.6%	11.50	\$2.69	\$1.55	\$20.45
Osborne	1	187.4	2.0	2%	93.9%	10.40	\$2.69	\$4.70	\$51.60
Pelican Point	1	462.6	3.0	3%	91.4%	7.71	\$2.77	\$4.44	\$37.04
Playford B	4	222.0	6.0	5%	84.1%	15.00	\$4.04	\$1.55	\$27.20
Port Lincoln	3	74.6	3.0	3%	91.4%	11.67	\$8.31	\$21.03	\$253.75
Quarantine	5	217.9	4.0	3%	89.1%	10.35	\$8.83	\$9.92	\$111.60
Snuggery	3	65.7	4.0	5%	88.1%	15.00	\$8.31	\$21.03	\$323.88
Torrens Island A	4	478.8	4.0	5%	87.7%	10.80	\$8.31	\$8.35	\$98.49
Torrens Island B	4	779.0	4.0	5%	87.7%	10.50	\$2.08	\$5.97	\$64.70
Tasmania									
Tamar Valley CCGT	1	196.9	1.9	3%	93.6%	7.54	\$2.77	\$5.42	\$43.65
Bell Bay GT	3	119.4	3.0	1%	93.3%	11.50	\$4.15	\$4.73	\$58.51
Tamar Valley OCGT	1	57.7	3.0	1%	93.3%	11.50	\$4.15	\$11.44	\$135.73

DJ Walton Statement – VCAT

PLANT	NO UNITS	TOTAL SENT OUT CAPACITY	SCHEDULED MAINTENANCE (WEEKS PA)	EFFECTIVE FORCED OUTAGE RATE	AVAILABLE CAPACITY FACTOR	FULL LOAD HEAT RATE (SENT OUT)	VARIABLE O&M COST \$/MWH (SENT OUT)	VARIABLE FUEL COST \$/GJ	TOTAL VARIABLE COST \$/MWH (SENT OUT)
New South Wales									
Bayswater	4	2592.7	2.5	2%	93.3%	10.00	\$2.77	\$1.66	\$19.32
Colongra OCGT	4	664.7	2.5	3%	91.9%	11.84	\$9.55	\$12.29	\$155.13
Eraring	4	2594.4	2.5	4%	91.8%	10.08	\$2.77	\$1.94	\$22.32
Eraring GT	1	39.8	2.5	3%	91.9%	11.84	\$9.55	\$21.03	\$258.61
Hunter Valley GT	2	74.6	4.0	3%	89.1%	23.38	\$9.55	\$21.03	\$501.43
Loddon	4	1974.0	2.5	3%	92.3%	10.38	\$2.50	\$1.66	\$19.68
Mt Piper	2	1318.0	1.0	1%	97.1%	9.93	\$2.64	\$1.68	\$19.35
Murrumbidgee	2	564.0	43.0	10%	15.8%	10.67	\$2.75	\$1.79	\$21.93
Redbank	1	141.0	2.0	2%	93.9%	11.00	\$2.77	\$0.34	\$6.54
Smithfield	1	151.2	3.0	20%	75.6%	10.00	\$5.27	\$4.66	\$51.83
Tollawarra	1	422.0	2.5	3%	92.3%	7.17	\$3.51	\$5.82	\$45.27
Uranginy	4	660.7	2.5	2%	93.3%	10.98	\$3.35	\$12.29	\$138.36
Vales Point	2	1240.8	3.8	4%	89.0%	9.87	\$3.46	\$1.99	\$23.07
Wallerawang	2	940.0	4.8	8%	83.9%	11.13	\$4.15	\$1.66	\$22.58

DJ Walton Statement – VCAT

PLANT	NO UNITS	TOTAL SENT OUT CAPACITY	SCHEDULED MAINTENANCE (WEEKS PA)	EFFECTIVE FORCED OUTAGE RATE	AVAILABLE CAPACITY FACTOR	FULL LOAD HEAT RATE (SENT OUT)	VARIABLE O&M COST \$/MWH (SENT OUT)	VARIABLE FUEL COST \$/GJ	TOTAL VARIABLE COST \$/MWH (SENT OUT)
Queensland									
Barclidine CC	1	48.8	3.0	3%	91.4%	8.02	\$4.15	\$3.86	\$35.11
Braemar	6	964.2	2.0	2%	94.2%	11.00	\$3.48	\$2.02	\$25.72
Callide A	Reserve	120.0	3.0	5%	89.5%	13.70	\$2.06	\$1.60	\$23.95
Callide B	2	656.0	2.0	3%	93.3%	9.88	\$1.99	\$1.61	\$17.68
Callide C	2	846.0	1.2	6%	91.8%	9.00	\$1.38	\$1.61	\$15.86
Collinsville	5	174.9	3.0	5%	89.5%	13.70	\$2.77	\$1.98	\$29.82
Darling Downs	1	617.4	2.0	1%	95.2%	6.70	\$3.44	\$1.55	\$13.78
Gladstone	6	1579.2	2.4	5%	91.1%	10.22	\$1.22	\$1.87	\$20.30
Kogan Creek	1	699.4	3.0	3%	91.4%	9.50	\$1.25	\$0.75	\$8.44
Mackay GT	1	31.8	2.0	2%	94.2%	13.50	\$11.08	\$21.03	\$295.09
Millmerran	2	763.8	3.0	6%	86.5%	9.88	\$1.25	\$0.75	\$8.72
Mt Stuart GT	3	412.9	2.0	2%	94.2%	11.50	\$5.53	\$21.03	\$247.47
Oakey GT	2	328.4	2.0	2%	94.2%	11.50	\$5.53	\$8.15	\$99.26
OAL Cogen	1	150.0	2.5	1%	94.3%	7.00	\$3.48	\$3.90	\$30.78
Roma	2	67.7	4.0	9%	84.0%	13.50	\$5.53	\$3.86	\$57.66
Stirwell	4	1380.9	1.8	1%	95.6%	9.99	\$1.10	\$1.67	\$17.77
Swanbank B	4	448.6	3.0	10%	84.8%	10.61	\$2.77	\$1.76	\$21.82
Swanbank E	1	358.9	2.0	2%	94.2%	8.10	\$2.77	\$3.86	\$34.04
Tarong	4	1316.0	2.2	2%	94.2%	10.06	\$1.15	\$1.26	\$13.76
Tarong North	1	416.4	2.4	2%	93.9%	9.00	\$1.15	\$1.38	\$13.60
Yabulu	1	235.7	3.0	2%	92.4%	7.44	\$2.77	\$3.26	\$27.00

Appendix C – New Entrant Assumptions

The Treasury; Carbon Pricing and Australia's Electricity Markets July 2011 – SKM MMA

Table 11 New entry cost and financial assumptions (\$ June 2010) for 2010/11

	TYPE OF PLANT	CAPITAL COST	AVAILABLE CAPACITY FACTOR	FUEL COST*	WEIGHTED COST OF CAPITAL	LRMC \$/MWH (a)
		\$ kW		\$ GJ	% real	
SA	CCGT	\$1,400	92%	\$5.11	11.30%	\$65.4
VIC	CCGT	\$1,300	92%	\$4.57	11.30%	\$53.3
NSW	CCGT	\$1,300	92%	\$4.47	11.30%	\$52.9
NSW	Black Coal	\$2,235	92%	\$1.92	11.30%	\$54.6
QLD	CCGT	\$1,300	92%	\$4.37	11.30%	\$51.3
QLD	Black Coal (Tarong)	\$2,235	92%	\$0.72	11.30%	\$44.0
QLD	Black Coal (Central)	\$2,235	92%	\$2.23	11.30%	\$57.3

* The fuel costs shown are indicative only. Gas prices vary according to the city gate prices.

(a) excluding abatement costs or revenues

Appendix D – CV of David Walton.

Address; c/o HRL Level 1, Unit 9,
67, Springvale Road,
Mulgrave,
Victoria 3170,

Executive Profile

Highly qualified and experienced CEO/Commercial Director/General Manager / CFO with an extensive international business background in energy, utilities and telecoms with leading national and global organisations.

Strong commercial acumen with particular expertise in financial management and operational leadership in highly complex and technical corporate environments.

Outstanding record of achievement in P&L and cash flow management delivering stretched financial, operational and compliance targets.

A champion of business growth through acquisitions and Greenfield developments as well as through organisational change, restructuring and business integration.

Professional Qualifications

2007 Australian Company Directors course.

1989 Fellow Chartered Management Accountants.

1984 Associate Chartered Management Accountants.

Career

Summary

Power Generation Consulting and Advisory Contract work.

2010

International Power:

1990 – 2010

Regional Director - Czech Republic
General Manager Business Development - Australia
General Manager Finance - Australia
Business & Finance Manager – Australian and Turkish projects.
Business and Finance Manager - UK power station
Management Accountant – UK Regional Office

1989-90

AEI Cables (GEC), UK Newcastle – Factory Cost Accountant

1984-89

British Telecom, UK Newcastle - Financial / Budget Manager,

1981-84

British Gas, UK Newcastle - Senior Accounting Assistant (Transmission & Distribution)

1980-81

Ingersol Rand, Gateshead - Accountant

1977-80

British Gas, Newcastle - Accountancy Assistant

Directorships

Responsible for governance, compliance and business ethics, strategic direction in line with parent requirements within independent and “ring-fenced” corporate and legal entities.

Australia; Pelican Point Power Ltd, Synergen Power Pty Ltd, International Power (Energy) Pty Ltd, International Power (Australia) Pty Ltd, IPM Australia Ltd, IPM Energy Holding Pty Ltd, Kwinana (Perth Power Partnership) and several holding and intermediary entities.

Europe; International Power BV, several the Czech Republic entities and several holding and intermediary entities including trusts and partnerships in Luxembourg, Netherlands and Guernsey.

Roles

Consulting and Advisory Contracting

September 2010 – Working for HRL Ltd / Dual Gas Pty on their DGDP development covering the commercial negotiations and project management for power off-take, gas, coal, O&M, debt and equity funding and the inter-commercial dependencies.

CEO Regional Director, Czech Republic (2008 - 2010)

Delivered profit, cash flow while mitigating risks. Complied with 'emission' limitations, secured fuel and business growth, in a safe manner, while meeting good industry practice for operations and maintenance. The business was very visible to the public, politicians and industry and so required significant management of relationships, partners along with management of political and industry 'expectations', in one of the worst 'business ethical' environments.

- The business consisted of:
 - 100% Opatovice; 360MWe 2.1TWh merchant power plus 700MWt, 4.2PJpa of district heating for two cities of 250,000+ residents and three 3 subsidiaries providing contract transport, and other services.
 - 50% Prazska Teplarenska; 13.1PJ of heat to 500,000 Prague residents plus 150GWh of associated power and a subsidiary providing contract R&M services
 - 50% of Energotrans; 360MWe up to 1.1TWh merchant plus 700MWt supply to Prague.
- Responsibility, autonomous control and management of;
 - P&L for the region of over £100m (A\$180m) and Cash Flow around £80m (A\$140m)
 - Fuel supply, operations, maintenance, HS&E, HR, finance, risk management, distribution, marketing and sales, retail and customer service.
 - Over 1400 staff; 550 staff at Opatovice and of over 920 staff Prazska Teplarenska and Energotrans.
 - Environmental, health and safety compliance.

General Manager, Business Development, International Power Australia (2005 - 2008)

- Responsible for a team of nine staff identifying, assessing, implementing growth opportunities both Greenfield developments and acquisitions including several gas monetisation projects and solar power.
 - Bid and final negotiations for three acquisitions (two unsuccessful, however one was a successful strategic ploy)
 - Developed material generation projects in NSW; 375MW and 80MW of OCGT stalled with the "privatisation process" in 2007.
 - Developed six wind farm sites in Victoria in advance of the government support.
 - Developed an 80MW OCGT expansion jointly with BP utilising refinery butane and gas at the Kwinana.

Kwinana Co-Generation Asset and WA Manager (2005)

Six month (plus) secondment as Power Station manager to the Kwinana Co-Generation plant (118MW CCGT plus refinery steam supplies). The main issue was to manage relationships and secure solutions for several operational areas at risk (water, environment and refinery gas).

- Responsible for
 - All commercial and Operation & Maintenance activities with all relationships with BP and Western Power for the fully contracted business.
 - A\$65m turnover and A\$19m P&L with 19 staff.

IPM (LYB, Valley Power and Kwinana) Integration Manager (2004 – 2005)

Assisted in the successful acquisition and then lead the integration of the ex-EME assets acquired in December 2004, covering commercial, trading, management of contract portfolio and market positions, accounting, communication and strategic direction.

- Responsible for
 - Pre-acquisition preparation and risk mitigation.
 - Post acquisition management and delivery of investment expectations.

General Manager Finance, International Power Australia (2000 - 2004)

As General Manager Finance for the Australian region, the role had scope covering Finance, Risk Management, Settlement, HR and IT with the management of up to 22 staff.

- The Australian business consisted of:
 - Hazelwood (1600MW Brown Coal), Pelican Point (450MW CCGT), Synergen (360MW Peaking), and Canunda Power (46MW wind farm), SEAGas (680km pipeline).
 - 50% of the non-NSW EnergyAustralia Retail activities (now 100%).
 - 1000MW LYB (lignite), 300MW (gas) peaking Valley Power and 118MW Co-Gen Kwinana power stations.
- Responsible for all financial aspects of to the local Regional Executive Director and to the UK parent
 - Turnover in excess of A\$800m and Profit From Operations of around A\$400m.
 - Asset base around A\$6bn (net assets A\$2bn).
 - Business planning and financial strategies, business and asset objectives and performance expectations.
 - Financial reporting, performance monitoring, financial and tax compliance.
 - HR. IT, Risk Management and external audit compliance.

Business & Finance Manager – Pelican Point Project, Australia (1999 – 2000).

Business & Finance Manager – Marmara Project, Turkey (1997 – 1999).

As Business & Finance Manager for the owning and operating company of the respective 480MW CCGTs (in Turkey and then in Australia), the general scope of the role covered all non-engineering or O&M activities.

- Responsibilities covered
 - Commercial, Procurement, Financial and Management Accounting, HR, H&S and Environment
 - Cash and Banking with debt management, draw-downs and repayment, FX and interest hedging
 - Full financial and management reporting and business planning.
 - Recruitment of business, operational, engineering and support staff.