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The sustainability of clean coal technology: IGCC with/without CCS

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ABSTRACT

Integrated gasification combined cycle power generation (IGCC) is one of the emerging clean coal technologies for reducing greenhouse emissions in coal-fired electricity generation. IGCC technology, both with and without CO_2 capture and storage (CCS) is compared with conventional super-critical power generation based on pulverized coal. The comparison is based on an equal consumption rate of Queensland black coal. The sustainability parameters being investigated are: thermal efficiency, environmental performance, inherent safety and economics.

The IGCC processes have been modeled using commercial steady-state mass and energy balance software. Both the gross and net thermal efficiencies of the IGCC power station are reduced when the plant is configured for CCS. The net efficiency is reduced from 32.1% to 26.1%, when 81% of the CO_2 is captured. This delivers an overall reduction in CO_2 emissions per unit of electrical energy output of 73.2% compared to the reference plant. However, environmental performance in other areas suffers as a result of switching to IGCC-CCS, particularly fresh water consumption is increased by 2.5 tonne/MWh for both coastal and inland locations. Inherent safety risks associated with IGCC are also greater with the gasifier being the highest risk unit in the facility with a Dow fire and explosion index of 168 compared with an index of 107 for a conventional boiler. Toxicity hazard also increases with carbon monoxide present at concentrations several thousand times higher than the TWA limit. The minimum viable selling price of electricity for a 7% IRR is calculated to increase from USD80 MWh^{-1} for a conventional power station to USD101 MWh^{-1} for IGCC and to USD145 MWh^{-1} for IGCC-CCS.

It is concluded that the application of IGCC-CCS is highly effective in reducing carbon dioxide emissions, the highest-profile problem associated with coal-fired electricity. There is an economic penalty which has been previously documented. However, there are also drawbacks concerning inherent safety and other environmental factors apart from CO_2 emissions, which until now have been under emphasized.

Keywords: Coal gasification; Thermal efficiency; Environmental performance; Inherent safety; Process economics

1. Introduction

Electricity is an essential amenity of modern society. Its presence and predominance has been used as a measure of the relative standard of living between rich and poor nations. The medium-to-long-term sustainability of electricity generation is a pressing case for evaluation, because of the breadth of alternatives, from micro-scale renewable energy to large centralized power stations fuelled by fossil fuels or fission material. The concepts of sustainability and sustainable development are the subject of much debate, but there is general agreement that the three pillars of sustainability: the society, the economy and the environment must all be considered and these evaluations must also consider a range of time frames from short to long (Adams, 2006).

The interaction between economic and environmental impacts of electricity generation is well reported, with 24% of anthropogenic CO_2 emissions derived from electricity generation (Stern, 2007). But where a country, such as Australia, is presently dependant on fossil fuels for electricity production,

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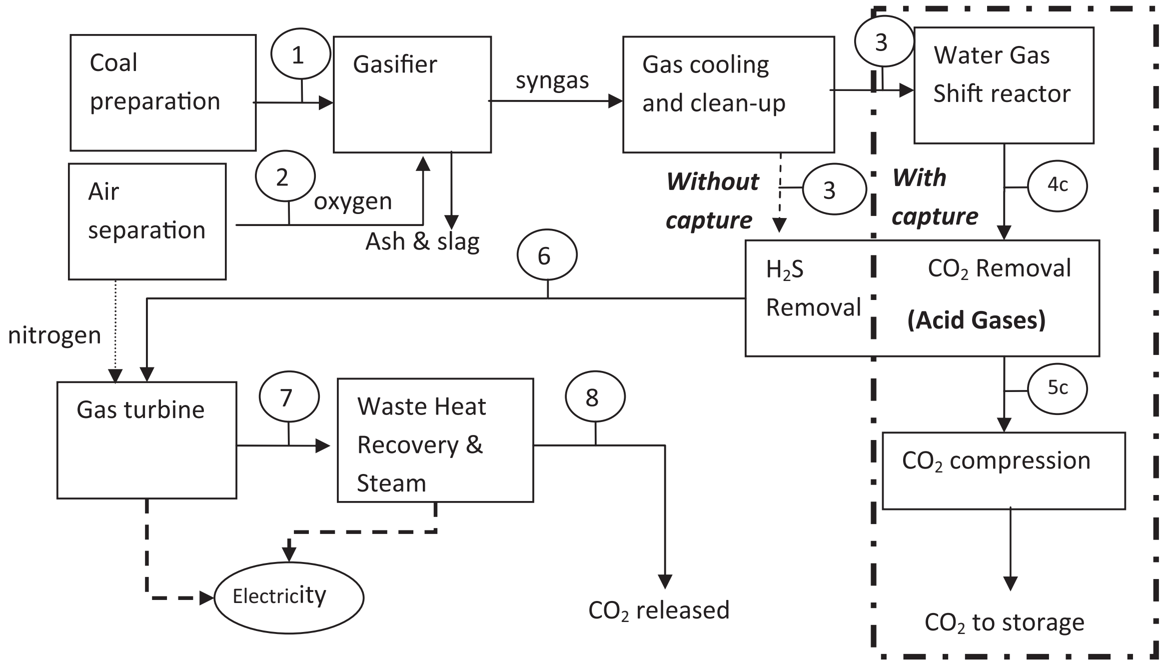

Fig. 1 – Block diagram for the IGCC process with/without CO_2 capture.

an abrupt cessation of this convenience would also have a profound social impact; therefore, the management of the transition towards sustainability is an important consideration. "Clean coal technology" is viewed as one pathway by which the industrialised world can improve the sustainability of its electricity generation, while facilitating a gradual social transition towards the same goal. Clean coal technology involves capturing CO_2 from the electricity generation process, and transporting the nearly pure CO_2 to a storage site. Storage, often referred to as sequestration, is usually in an ocean, depleted oil or gas field, or deep aquifer.

Carbon capture is not a single technology, but a suite of technologies, some of which can be applied to existing coal-fired power stations and some of which involve new technologies for transforming coal into energy. This paper will investigate just one of the newer technologies: integrated gasification and combined cycle power generation (IGCC). This investigation involves a relatively standard IGCC flowsheet for two cases: with CO_2 capture and without CO_2 capture. Both flowsheets have been optimized and the results are compared with a new conventional super-critical pulverized coal power station without CO_2 capture. This allows the impact of IGCC clean coal technology to be evaluated in a life cycle assessment, an inherent safety assessment and an economic analysis.

2. IGCC with and without capture technology

Fig. 1 shows a block diagram for an oxygen-blown IGCC process with and without capture. Synthesis gas (syngas) is produced in the gasifier. In the "without capture" case, after cooling and cleaning this gas, it passes directly to the gas turbine for power generation. The components within the dashed rectangular box, namely the water gas shift reactor, acid gas capture and compression steps are required for CO_2 capture and storage. H_2S removal is required in both cases.

There are many process alternatives for IGCC. However, for large IGCC-CCS power projects the industry is tending towards a common arrangement: entrained-flow gasification, sour water gas shift reactors and the use of a glycol-based physical solvent "Selexol" for acid gas removal (IEA GHG, 2003; Metz et al., 2005). Table 1 summarises the different technology choices for these blocks of the process. In this study, the CO_2 and H_2S are assumed to be co-sequestered. Ordorica-Garcia et al. (2006) claim that the capital cost for capture facility is reduced by around 80%, if the H_2S is not separated from CO_2 and converted to sulfur; making it substantially cheaper to co-sequester H_2S with CO_2 than produce two products. At present there is no limitation on H_2S injection by convention or law, but similarly there is a dearth of test data to support the long-term viability of co-sequestration.

The gasifier in particular is dependent upon the properties of the coal. The coal is assumed to be a Queensland black coal with the composition given in Table 2. This coal has relatively low sulfur content. The ash content is also important as low ash coals can cause problems in slagging gasifiers, but the addition of limestone mitigates these problems (Patterson and Hurst, 2000).

3. Methodology

3.1. *Basis for comparison*

Table 3 defines the three process cases where the basis for comparison is an equal coal consumption rate of 4369 tonne d^{-1}. Case A is the reference case of a new supercritical boiler with limestone desulfurization, but no CO_2 capture. Cases B and C are IGCC without and with CCS, respectively. The net electricity output for each case reduces from Case A to B to C and as the coal consumption rate is identical this represents the same proportional reduction in the net thermal efficiency. The comparison based on an equal coal consumption rate leads to a similar rate of CO_2 production for the three cases. The reason for not choosing an identical electricity production rate was one of scale mismatch: e.g. a 500-MW plant required two gasification units for Case C, but a pulverized coal power station producing the same power as a

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Table 1 – Summary of technology selection.

Process block	Options (preferred)	Justification
Gasification	1. Moving bed 2. Fluidised bed 3. Entrained flow (slagging/non-slagging)	Oxygen-blown entrained-flow gasifiers are the preferred option for large scale operations (Metz et al., 2005) using bituminous coal. The coal is pulverized to smaller than 100 μm and because of this gasification occurs with residence times of only a few seconds, the advantage of which is the absence of tar, oil or phenol formation. High temperatures allow molten slag with low carbon content to be recovered (Schaub, 2007). A slagging gasifier also offers protection to the gasifier walls from the slag and the slag is easily separated at the base.
Syngas cooling	1. Integrated boiler 2. Water quench	Due to the cost, materials and safety aspects, syngas must be cooled shortly after gasification. Waste heat boiling provides the best efficiency, but the equipment is large, must be able to withstand very high temperatures, leading to substantial capital costs and materials challenges, and soot and slag deposition cause fouling problems (IEA Clean Coal Centre, 2008). The alternative is a quench gasifier which employs a combination of cooling techniques including a direct water quench, which also increases the H_2O:CO ratio in the syngas.
Water gas shift reaction (WGSR)	1. Sweet gas shift 2. Sour gas shift	WGSRs are classed by catalyst type: sweet and sour. Sweet shift catalysts are poisoned by H_2S and COS; sour shift catalysts are resistant to sour gases, rely on a minimum H_2S loading for activation (Hakkarainen et al., 1993), and will hydrolyze COS to the more easily separable H_2S. Maurstad (2005) claims that the capital cost of an IGCC plant with sour shift is $77/kW cheaper and has plant efficiency 1.5%pts higher than one with sweet shift, because the syngas must be cooled before sweetening, which condenses any water present, which must afterwards be re-injected to get the H_2O:CO ratio above 2.0.
Acid gas removal (AGR)	1. Chemical absorption 2. Physical absorption Rectisol/Selexol 3. Pressure swing adsorption (PSA)	A physical absorption process is chosen because the energy required for regenerating a physical sorbent through flashing and pumping is significantly lower than for regenerating a chemical solvent by steam stripping, and because the syngas pressure (>30 bar) is sufficiently high for a physical separation to be practical (UOP LLC, 2007). The low energy requirement for PSA, high integration, and ease of retrofitting for higher throughputs are attractive, but the size of the PSA system is unproven and the batch nature of PSA requires temporary hydrogen storage to ensure a continuous supply to the gas turbine, introducing an unnecessary inherent major hazard. The two most commonly used physical solvents are the methanol-based, Rectisol and the glycol-based, Selexol. Rectisol has been used most frequently in processes producing chemicals, because it produces a cleaner syngas, including the removal of heavy metals, but the capital and operating costs associated with refrigerating it to −40 °C are higher, and there are serious inherent health risks associated with the toxicity of methanol (Manning and Thompson, 1991; Korens et al., 2002). Selexol is non-toxic and it has been the solvent of choice for all 15 IGCC studies reported in the IPCC special report (Metz et al., 2005).

single-gasifier power station would be of unrealistically small scale by today's standards. Instead by assuming an equal coal consumption rate, based on the maximum current size of a single entrained-flow gasifier, the scale of the IGCC processes are maximized without unduly penalising the conventional pulverized power station. Each case is assumed to be operated on the east coast of Australia, close to the source of the coal. As water is considered to be a scarce resource in parts of Australia, the study will also consider the availability of seawater as a coolant for condensing steam and the life cycle assessment results will be presented for both cases where seawater is and is not available. The prevailing ambient conditions, based conservatively on average summer afternoon conditions, are given in Table 4.

Table 2 – Coal feedstock composition.

Component	Content	Analytical basis
Carbon	86.5%(w/w)	Ultimate analysis, dry ash-free basis
Hydrogen	5.0%(w/w)	Ultimate analysis, dry ash-free basis
Nitrogen	2.0%(w/w)	Ultimate analysis, dry ash-free basis
Sulfur	0.85%(w/w)	Ultimate analysis, dry ash-free basis
Oxygen	5.65%(w/w)	Ultimate analysis, dry ash-free basis
Ash	15%(w/w)	Proximate analysis, dry basis
Moisture	8%(w/w)	Proximate analysis, as-received basis
Lower heating value		24.3 MJ/kg

Table 3 – Definition of Cases.

	Description	Coal consumption rate (tonne d^{-1})	Net power output (MW)
Case A	Supercritical boiler without CCS	4369	455
Case B	IGCC without CCS	4369	394
Case C	IGCC with CCS	4369	321

Table 4 – Climatic data based on east coast Australia (January).

Ambient temperature	31.2 °C	Based upon average maximum temperature
Wet bulb temperature	23.8 °C	Based upon average at 3pm
Design cooling water supply temperature	27.8 °C	Based upon 4 °C approach temperature to the wet bulb temperature
Relative humidity	64%	Based upon average at 3pm

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Table 5 – Stream data for Fig. 1: Case B without capture, Case C with capture.

	2	3	4c	5c	6b	6c	7b	7c	8b	8c
Temperature (°C)	20	230	465	50	50	40	540	536	120	120
Pressure (bara)	44	38.6	37.8	20	33.8	30	1.07	1.07	1.01	1.01
Mass flowrate (tonne/h)	155	706	706	367	322	109	3804	3420	3804	3420
	Mole fractions									
	2	3	4c	5c	6b	6c	7b	7c	8b	8c
H_2O		0.575	0.348	0.008	Trace	Trace	0.032	0.100	0.032	0.100
CO		0.278	0.051	0.005	0.660	0.120	Nil	Nil	Nil	Nil
H_2		0.114	0.341	0.026	0.270	0.806	Nil	Nil	Nil	Nil
CO_2		0.0024	0.230	0.952	Trace	0.006	0.079	0.016	0.079	0.016
N_2	0.023	0.0253	0.025	0.003	0.060	0.059	0.759	0.737	0.759	0.737
Ar ($\times 10^{-3}$)	27	3.55	3.55	0.40	8.42	8.31	9.7	9.7	9.7	9.7
H_2S ($\times 10^{-3}$)		0.922	1.01	4.12	0.023	0.046	Nil	Nil	Nil	Nil
CH_4 ($\times 10^{-3}$)		0.283	0.283	0.242	0.672	0.544	Nil	Nil	Nil	Nil
COS ($\times 10^{-3}$)		0.100	0.008	0.034	Nil	Nil	Nil	Nil	Nil	Nil
HCN ($\times 10^{-3}$)		0.078	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil
NH_3 ($\times 10^{-3}$)		0.018	0.096	0.045	Nil	0.001	Nil	Nil	Nil	Nil
O_2	0.95	Nil	Nil	Nil	Nil	Nil	0.141	0.138	0.141	0.138

3.2. *IGCC mass and energy balances*

The two IGCC processes (Cases B and C) have been simulated using commercial steady-state mass and energy balance software (Aspen-Hysys™). The vapour-liquid thermodynamics has been modelled using the Peng–Robinson equation-of-state for the synthesis gas (Twu et al., 1995) and as discussed in Section 3.2.4, a modified Henry's Law is used for the Selexol absorption and stripping. The stream data for the main process streams (Cases B and C) shown in Fig. 1 are provided in Table 5.

3.2.1. *Gasification*

The synthesis gas composition and conditions were provided by a gasification technology supplier from unpublished data for the Australian coal considered in the study. The gasifier was modelled on a Prenflo Gasifier™ and is designed to operate at 40 bara with a maximum temperature of around 2000 °C. The gasifier effluent conditions (taken downstream of the water scrubbing processes, and upstream of water gas shift reactor) are given in Table 5. The synthesis gas flowrate for both cases is 16940 tonne d^{-1}. The gasifier is assumed to require 0.058 MWh/tonne of coal in electrical utility and the waste water flowrate is 0.87 tonne/tonne coal. It is also assumed that all sulfur and nitrogen leaving the gasifier unit is contained in the syngas or waste water. There will also be some small amount of sulfur bound in the slag; however, the amount is difficult to quantify (Shadle et al., 2001) and has not been considered.

3.2.2. *Reactions*

In Case B, COS is hydrolyzed to form CO_2 and H_2S and the reaction is assumed to go to completion by passing the syngas over an alumina catalyst. In Case C, CO and H_2O are shifted to H_2 and CO_2 over a CoO/MoO_3 catalyst doped with TiO_2/ZrO_2, and the reaction is assumed to reach 95% approach to equilibrium. COS is assumed to be simultaneously hydrolyzed to form CO_2 and H_2S, catalyzed by the alumina carrier of the shift catalyst.

3.2.3. *Syngas cooling and water recovery*

In both cases the syngas is cooled to close to ambient temperature, prior to acid gas removal. As will be explained in Section 3.2.6, the energy associated with cooling the syngas below 200 °C is not recovered. The majority of the water in the syngas is condensed; furthermore, the majority of the ammonia is dissolved in the condensed water. This is favourable, as two undesirable components can be gravity separated from the syngas by adding a knock-out drum prior to the acid gas treatment. It is desirable to recycle the water to the reactor, reducing the freshwater requirements of the gasifier. The water is collected in two stages as the syngas is cooled, but most of the ammonia is obtained only in the second stage. In order to prevent the accumulation of ammonia, it is removed by an alkali stripping process. Low pressure steam is used in this study to strip the ammonia from the water collected in the second stage.

3.2.4. *Sour gas removal and CO_2 compression*

For Case B, H_2S is removed from the syngas using a DEA absorber. Using the data (Maddox and Morgan, 1998) the necessary sulfur removal is achieved by recirculating 4100 tonne d^{-1} of 20 wt% DEA at 50 °C. The stripper reboiler (heated by low pressure steam) has a duty of 12.7 MW; 0.5% of CO and H_2 are assumed to be absorbed by the DEA and are not recovered. The cost of replacing DEA was assumed to be insignificant.

For Case C, H_2S and CO_2 are removed from the shift gas using Selexol at 40 °C. A modified Henry's law model is required to provide a realistic circulation rate which was compared with the circulation rate quoted by Ciferno (2007) of 250,000 tonne d^{-1}. In this study a flowrate of 190,000 tonne d^{-1} of recirculating Selexol is used to achieve the separation with an absorption factor of 1.0. The Selexol is regenerated by flashing to 20 and 5 bar, heating to 94 °C and flashing further to 1.25 and 0.3 bar, before recooling to 40 °C and pumping back to the columns. The operating pressure of the absorber column is 30 bar. Selexol is heated during regeneration primarily through cross-exchange, but the last 10–15 °C is achieved with LP steam. The utility duty required for this heating is 45 MW.

After capture (Case C) the acid gases are compressed to 150 bar for geosequestration. The gas is compressed between each of the flash levels in two stages with intercooling by air to 50 °C. The compressors are assumed to have an isentropic efficiency of 82%. At the high pressure level, moisture is removed

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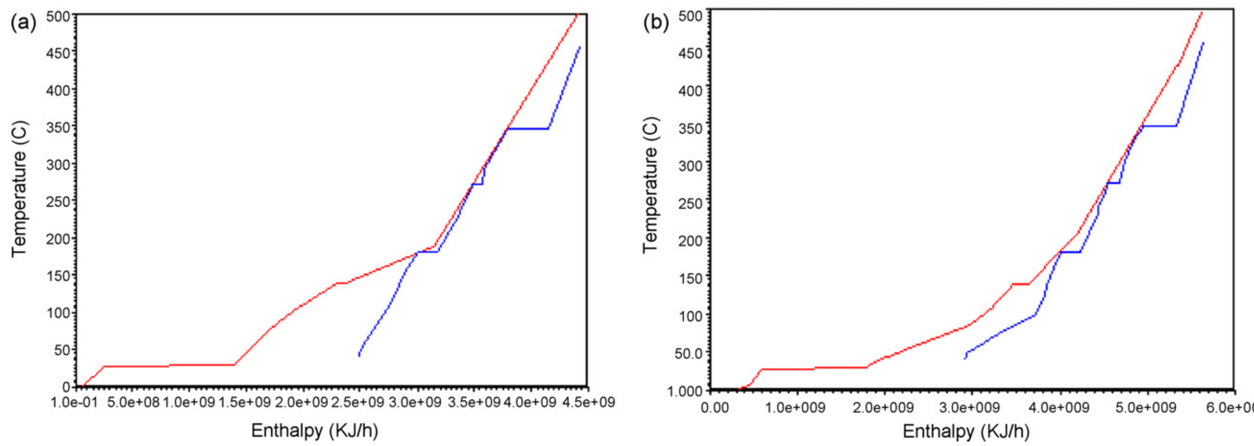

Fig. 2 – Shifted composite curves for IGCC (a) Case B and (b) Case C.

from the CO_2 stream using a triethylene glycol (TEG) desiccation plant to avoid hydrate formation and increased pipeline corrosion (Aspelund and Jordel, 2007). The regeneration of the TEG is assumed to require 1.2 MW of MP steam. When the acid gases are supercritical, this stream is pumped to 150 bar and cooled again to 50 °C ready to be sent for sequestration. The final pressure is somewhat arbitrary and many studies assume 100 bar. The higher pressure internalizes some of the pumping costs, but these are not very significant.

3.2.5. *Combined cycle power plant*

The gas turbine data is based upon the Siemens SGT5-2000E. A simplifying assumption was that the turbine can be directly scaled to match the available fuel for both the capture and non-capture plants; in an actual design, the plant output would match the size of the available gas turbine. The power output is scaled back based on an ambient air temperature of 25 °C. It is assumed that the gas turbines are not integrated with the air separation unit. This is based upon the findings of Rieger et al. (2008) that there are only small increases in efficiency to be achieved through integration and these are largely outweighed by operability and reliability challenges.

The gas turbine exhaust is assumed to be available at 536 °C, 1.07 bar. The heat recovery steam generator (HRSG) is assumed to be a four level system, with pressures at 4, 9, 52 and 150 bar. Header pressures are assumed to be 5% lower. The HP and MP steam are both superheated to 450 °C. The turbine isentropic efficiencies are assumed to be 83.5% (81% for LP turbine) and the mechanical efficiency is assumed to be 99.5%.

3.2.6. *Process integration*

A classical heat integration analysis (Linnhoff and Flower, 1978) has been conducted for both gasifier cases. A $\Delta T_{min} = 40$ °C is used for gas/gas heat exchange and $\Delta T_{min} = 10$ °C assumed for all other streams. Fig. 2 shows the shifted composite curves for Cases B and C. Three pinch points can be observed for each case. Each of these represents steam production in the HRSG. The amount of steam produced at each level was optimized to maximize the steam turbine output. The lowest of the pinch points represents the temperature below which there is a surplus of waste heat. The philosophy for cooling below this point is that air cooling is used for all cooling duties above 100 °C and for all compressor inter-stage coolers; either seawater or recirculated cooling water is used for all other cooling duties below 100 °C; only the low pressure condensing steam is condensed with seawater and this is applies only to the coastal location.

3.2.7. *Utilities*

3.2.7.1. *Condensing steam*. For a coastal location, the low pressure condensing steam is condensed with seawater. The seawater is assumed to be used in a once-through system where it is pumped to 3 barg, has a maximum 5 °C temperature rise, and where the seawater pumps run at 85% efficiency. For an inland location, low pressure steam condensing is achieved with a recirculated cooling water system. This water is pumped to 7 barg, and the pumps run at 85% efficiency. The maximum cooling water temperature rise is 10 °C and the cooling tower blowdown is set to 14 cycles of concentration.

The air separation unit is assumed to require 0.532 MWh/tonne of coal in electrical utility and 45 tonne recirculated cooling water/tonne coal.

3.3. *Economic analysis*

This study aims to calculate the relative costs of generating electricity with and without carbon capture. It compares three new installations at a common location in Queensland, Australia. The capital costs were estimated using data which was generally provided in USD and these values were inflated using the CE plant cost index for North America to December 2008. Operating costs were mainly estimated in 2008 AUD. The economic results are presented as a function of the AUD/USD exchange over a broad range, which eliminates the uncertainty associated with this variable.

3.3.1. *Definitions for the cost of CO_2 capture*

For Case C, IGCC with CCS, the scope of this work does not extend to the cost of CO_2 storage (i.e. piping to and the cost of operating the storage site). For the purposes of comparison, transport and storage costs have not been added to either the cost of electricity from CCS or the cost of CO_2 capture. The cost of carbon capture has been calculated on two bases: C_{CC}, per megawatt hour of electricity sent out and $C_{CO2\,avoided}$ per tonne of CO_2 avoided through capture, as given in Eq. (1):

$$C_{CC} = C_{IGCC} - C_{ref} \tag{1a}$$

$$C_{CO2\,avoided} = \frac{C_{CC}}{e_{ref} - e_{IGCC}} \tag{1b}$$

Table 6 – Capital cost estimates for the IGCC power options (USDmillions).

Equipment type	Case B purchase price	Case C purchase price	References
Gasifier	393.7	393.7	
Heat exchangers	5.8	20.0	Peters et al. (2003)
Heat recovery steam generator	29.9	31.1	Thermoflow Inc. (2008)
Steam turbines + generator	36.6	38.0	Thermoflow Inc. (2008)
Gas turbine + generator	68.1	63.9	Thermoflow Inc. (2008)
Steam condenser	3.9	4.0	Thermoflow Inc. (2008)
Deaerator	1.0	1.0	Thermoflow Inc. (2008)
CO_2 compressor		44.7	
Drums	1.0	2.4	Peters et al. (2003)
Columns		6.1	Peters et al. (2003)
Tanks	0.4	0.8	Peters et al. (2003)
Reactors	0.3	0.5	Peters et al. (2003)
Recirculated cooling	1.8	4.5	
Waste water treatment	5.2	5.2	
Glycol drying unit/DEA unit	1.8	4.1	Muniandy (1997)
Pumps (exc. recirc. cooling)	4.5	4.6	Peters et al. (2003)
Total capital cost of installed plant	1314.0	1574.5	

Table 7 – Economic parameters common to the three power stations.

Coal (AUD/tonne) *Based on 1.5 AUD/GJ*	36.45
Limestone (AUD/tonne)	9.77
Town water (AUD/tonne)	2.0
Boiler feed water (AUD/tonne)	4.0
Natural gas (AUD/GJ) *Required for startups*	3.5
Selexol (AUD/tonne)	8794
Ash disposal (AUD/tonne)	10
Wastewater treatment (AUD/tonne)	1.0
Plant availability	0.85
Operators/shift (5 shift rotation)	2 × No. zones + 2
Operator salaries (AUD/years)	105,000
Other staff	0.9 × operator salaries
Staff overheads	0.3 × salaries
Maintenance (and supplies)	0.022 × fixed capital
Plant overheads (incl. laboratory)	0.35 × salaries
Insurance and tax	0.02 × fixed capital
Royalties (gasifier only)	0.01 × gasifier capital
Discount rate per annum	0.07
Design (years)	2
Construction (years)	3
Operation (years)	20

Table 8 – Mass flowrates used in LCA.

	Case A	Case B	Case C
Inputs			
Coal (black) (tonne/d)	4369	4369	4369
Limestone (tonne/d)	84	275	275
Fresh water			
Inland (ktonne/d)	25.4	26.1	37.3
Coastal (ktonne/d)	0.73	14.8	25.8
Outputs			
Electricity (MWh/d)	10920	9456	7704
CO_2 (tonne/d)	10651	10651	2016.7
SO_2 in flue gas (tonne/d)	53.7	0.547	1.07
SO_4^{2-} in wastewater (tonne/d)	0	134.95	82.26
NO_x in flue gas (tonne/d)	207.9	0.59	0.53
NO_3^- in wastewater (tonne/d)	0	246.8	246.8
Ash (tonne/d)	558.3	98.2	98.2

where C_{IGCC} and C_{ref} are the cost of electricity production in $/MWh for IGCC and for the new pulverized coal power station without capture (Case A). e_{ref} and e_{IGCC} are the emissions of CO_2 in tonnes/MWh for Case A and IGCC plants, respectively.

3.3.2. *Capital and operating costs*

Case A is a new super-critical conventional pulverized coal power station without CO_2 capture. The capital cost for Case A is US$1365million is based on recent EPRI estimates of USD3000/kW of installed capacity for such a plant (Holt et al., 2009).

For Cases B and C, the capital costs are broken into the different package items and generic equipment types (such as heat exchangers, pumps, etc.), as shown in Table 6. For packaged items, such as the gasifier package, an installation factor of 1.4 has been assumed; for generic equipment, the installation factor was 2.7. An additional 5% has been allowed to account for outside battery limits costs.

Operating costs are summarized in Table 7 with both consumables and labour. The conventional pulverized fuel power station has three zones of activity, whereas Cases B and C have four and five zones, respectively; these zones allow the estimation of the number of operators and are defined in more detail in Section 3.5, dealing with inherent safety. A discount rate of 7%, typical of public utilities, has been assumed. The operating cost is prior to depreciation and tax. The break-even electricity price is determined for each case based on a zero net present value at the end of 20 years of operation.

3.4. *Life cycle assessment*

Life cycle assessment (LCA) seeks to quantify the environmental impacts of the three power generation systems. The unit of comparison (or functional unit) used in the LCA is 1 MWh of electricity exported. This unit was selected on the basis of electricity being the product, and to facilitate comparisons with other power generation systems. This selection contrasts with the selection of coal consumption rate as the unit of comparison for economic and safety criteria; coal consumption was selected because of the dominant contribution of the gasifier to capital and operating costs and to safety risks.

The system boundary is restricted to the battery limits of each plant including utilities and thus, the coal mine and coal transport to the plant are excluded. Because the coal consumption rate is the same for the three processes, any environmental impacts associated with the coal mine and transport will have a slightly greater impact in the two IGCC processes, as their net efficiencies are lower. The system boundary also excludes the embedded energy consumption

Table 9 – Dow fire and explosion worksheet for the gasifier and the boiler.

Process unit	Gasifier & syngas cooling		Boiler
Materials in process unit	Coal dust, CO, H_2S, COS, H_2O, H_2, HCN		Coal dust
State of operation	Normal		Normal
Basic material for material factor	Hydrogen		Coal dust
Material factor (MF)	21		16
	Penalty range (if applicable)	Penalty applied	Penalty applied
1. General process hazards			
Base factor	1	1	1
A. Exothermic chemical reactions	0.3 → 1.25	0.5	0.5
B. Endothermic processes	0.2 → 0.4	0.4	0
C. Material handling and transfer	0.25 → 1.25	0	0
D. Enclosed or indoor process units	0.25 → 0.9	0	0
E. Access	0.2 → 0.35	0	0
F. Drainage and spill control	0.25 → 0.5	0	0
General process hazards factor (total)	1.9	1.5	
2. Special process hazards			
Base factor	1	1	1
A. Toxic materials	0.2 → 0.8	0.8	0.2
B. Sub-atmospheric pressure	0.5	0	0
C. Operation in or near flammable range			
C1. Tank farms storage flammable liquids	0.5	0	0
C2. Process upset or purge failure	0.3	0	0
C3. Always in flammable range	0.8	0.8	0.8
D. Dust explosion	0.25 → 2.0	1.25	1.25
E. Pressure		0.864	0
F. Low temperature	0.2 → 0.3	0	0
G. Quantity of flammable/unstable material			
G1. Liquids, gases and reactive materials in process		0	0
G2. Liquids or gases in storage		0	0
G3. Combustible solids in storage, dust in process		0	0
H. Corrosion and erosion	0.1 → 0.75	0.1	0.2
I. Leakage—joints and packing	0.1 → 1.50	0.3	0
J. Use of fired heaters		0	1
K. Hot oil heat exchange system	0.15 → 1.15	0	0
L. Rotating equipment	0.5	0.3	0
Special process hazards factor (total)		5.414	4.45
Unit hazard factor (UHF)		8	6.675
Fire and explosion index = UHF × MF		168	106.8
Assessment of hazard		Severe	Intermediate

and emissions associated with plant construction activity. Furthermore, emissions are based solely upon the steady-state mass and energy balances and fugitive emissions are also neglected. In practice, leakage and flaring of gases would be much more likely in the two gasification processes.

The total mass flow rates, based upon a full operational day, are given in Table 8. The flue gas from the pulverized coal plant is scrubbed with limestone to remove sulfur and the sulfur removal efficiency is assumed to be 85%; fuel nitrogen is assumed to form NO_2 and this is not treated. Slag from the gasifier is assumed to form a saleable product, which does not go to land fill and therefore only ash is considered as a solid waste.

3.5. *Inherent safety analysis*

Inherent safety analysis is a tool for selecting and designing a process to eliminate hazards, rather than accepting the hazards and implementing add-on systems to control them. It is particularly useful for comparing process options which have different reaction paths. The Dow fire and explosion index (American Institute of Chemical Engineers (AIChE), 1994), the Mond index, the prototype index of inherent safety (PIIS) (Edwards and Lawrence, 1993), the inherent safety index (ISI) (Heikkila, 1999), i-Safe index (Palaniappan et al., 2004) and I2SI index (Khan and Amyotte, 1998) all attempt to quantify risks associated with different process routes. However, the Dow fire and explosion index permits a more detailed study by taking into consideration materials, design factors and layout, which can either increase or decrease the risk of a fire or explosion hazard. This is conducted on a unit by unit basis, where the results can be used to determine the minimum separation distance required between units.

In the case of the conventional power station, there are three process zones: coal preparation, the boiler and the electrostatic precipitators (ESPs). In the cases of the IGCC processes, the process zones are: coal preparation, ASU, gasifier, shift reactors and syngas cleanup, acid gas removal, gas turbine and HRSG; in the case of carbon capture, there is also the CO_2 compression zone. For each zone a worksheet is produced which determines the fire and explosion index. From this value, the economic cost of a fire or explosion can also be estimated. Table 9 provides an example of a worksheet for the calculation of the index for the gasifier (judged to be the greatest risk

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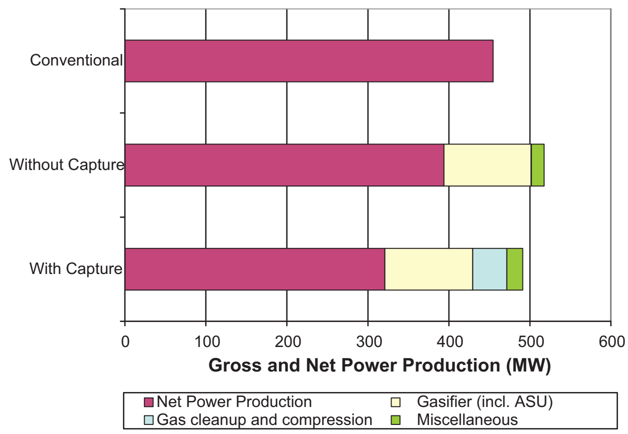

Fig. 3 – Gross and net power production showing the consumption within the different sections of the IGCC process for a coal consumption rate of 4369 tonne d^{-1}.

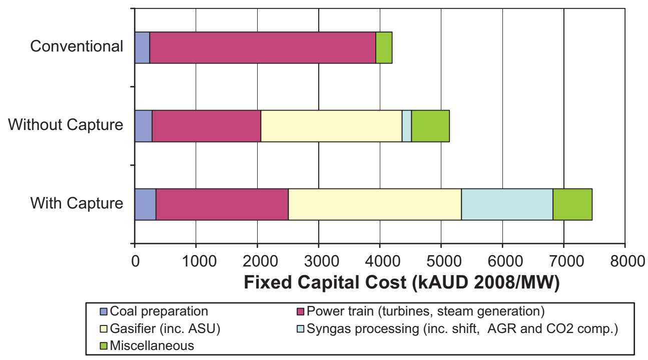

Fig. 4 – Fully installed capital costs for the three power plants in Australian Dollars per MW of installed capacity showing the breakdown between the four main sections of the process for a coal consumption rate of 4369 tonne d^{-1}. The miscellaneous section refers to water treatment, the cooling water system and the outside battery limits of 5% of the inside battery limits capital.

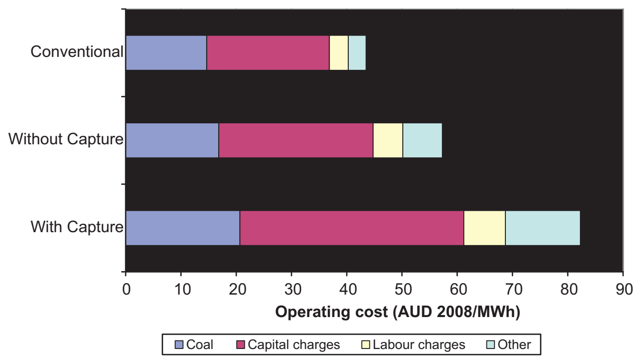

Fig. 5 – Specific operation costs in Australian Dollars per MWh of net electricity production for a coal consumption rate of 4369 tonne d^{-1}.

for the IGCC processes) and the boiler for the conventional coal process. In regard to Table 9, the following assumptions have been made:

1. The material factor for the gasifier is chosen to be hydrogen due to its high molar concentration and wide flammability range. For the conventional boiler, it is coal dust.
2. Both exothermic and endothermic reactions occur in the gasifier as the gasification reaction is endothermic, but the combustion of char (like coal in a conventional boiler) is exothermic, and different reactions predominate in different zones of the gasifier.
3. It is assumed that there are no significant volumes of flammable liquids associated with the gasifier or boiler and that both are designed to have good access.
4. In the gasifier, the toxicity factor was based on hydrogen cyanide. For the conventional boiler, it was based on coal dust.
5. A general corrosion rate of less than 0.5 mm/year was assumed for the gasifier, but a higher value was assumed for the boiler, based on atmospheric operations, larger piping and more potential for fouling and erosion.
6. There are many high pressure flanges in the case of the gasifier, particularly those associated with the synthesis gas quench compressor.

4. Results

4.1. *Thermal performance*

Fig. 3 shows the gross electricity production from the three processes. Case B (the IGCC without capture) has the largest electricity production of 517 MW. This is 5% higher than Case C of 491 MW, which represents a 2.1%pts difference in gross thermal efficiency (42.1% *cf.* 40.0%). This difference exists because there is a small reduction in the molar heating value of the synthesis gas due to the exothermic shift reaction. The gross electricity production was not calculated for the conventional plant, Case A, as the costs were based on the net production. Case A has a net thermal efficiency of 37%, which gives it the largest net electricity production of 455 MW. The electrical utility requirements of the ASU and gasifier result in a loss of around 108 MW for both IGCC cases. The acid gas removal and compression requires a further 42 MW of electricity for Case C. Miscellaneous losses include pumping duties for the HRSG and cooling water systems and air cooler fan motors. As Case C has more waste heat to dissipate than Case B, the miscellaneous duties are around 20% higher (19.7 MW *cf.* 15.7 MW). The net electricity productions are 394 and 321 MW, for cases B and C, respectively.

4.2. *Economic assessment*

Fig. 4 shows the capital costs for the three processes in 2008 AUD/MW of installed capacity, broken into the main plant sections. In the case of the coal preparation section, this is identical in all three cases and the different lengths of the bars reflect the different net efficiencies. Similarly the total installed cost of the gas turbine and HRSG are slightly greater for Case B, reflecting the slightly greater electricity production, but in Fig. 4 the specific cost per MW is lower.

Fig. 5 provides the operating cost for running the plant broken into the major components of fixed and variable costs. The proportional costs are similar for the three cases. For the conventional plant, the cost of coal makes up 39% of the total operating cost compared with 29% and 25% for Cases B and C, respectively. Capital charges included maintenance, insurance and land taxes and royalties. Labor charges included direct labor, payroll overheads, plant overheads and the laboratory costs. The increasing labor charges represent the greater number of operating units and complexity of the process moving from the Case A to B to C.

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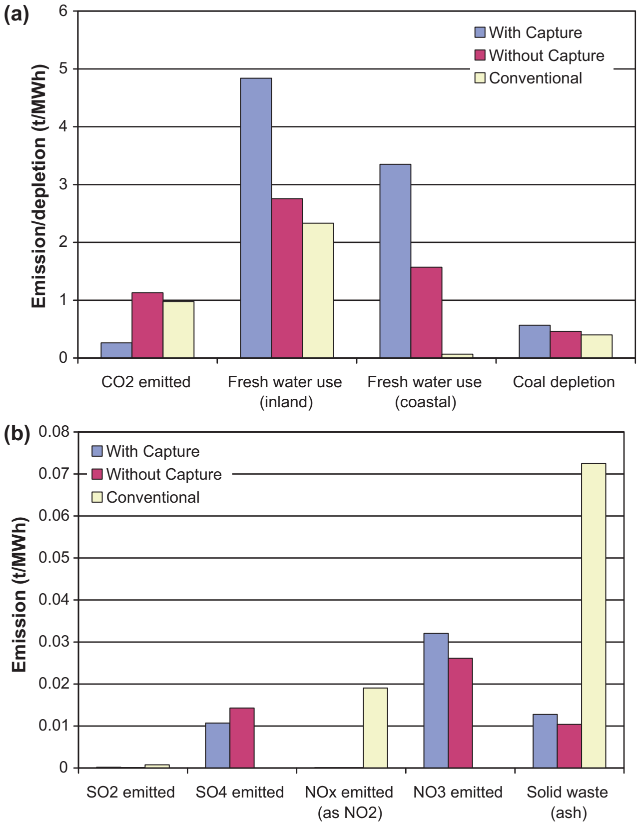

Fig. 6 – Inventory data per unit MWh of net electricity production: (a) higher mass inventories and (b) lower mass inventories.

A discounted cash flow analysis for the three processes based on an electricity price that would yield a 7% rate of return over the 20-year project life (with zero inflation rate) gave a range of electricity prices depending on the AUD/USD exchange rate. For example for a conventional coal power plant, the selling price ranged from AUD109 to AUD122/MWh for AUD/USD of 0.8 to 0.6, respectively. The mid price at an exchange rate of 0.7 for Case 1 was USD80 MWh^{-1}. The mid-prices for Cases B and C were USD101 MWh^{-1} and USD145 MWh^{-1}, respectively.

4.3. *Environmental assessment*

The environmental impacts have been calculated from life cycle inventories, as previously described, on the basis of 1 MWh of net electricity production. Fig. 6a shows the large emissions in tonnes per MWH. As expected, the CO_2 emissions for Case C are only 27% of the conventional coal power station. This corresponds to the specification of 80% capture of all the carbon consumed by the gasifier. The CO_2 emissions for Case B are higher than for conventional coal, reflecting the slightly lower efficiency of the non-capture IGCC process.

Resource depletion is considered with respect to both coal and water, where water is of particular importance in Australia. The two groups of water consumption data (inland and coastal) differ in that recirculated cooling water, replenished by freshwater, is assumed to be used to condense the steam for a power station located inland, whereas seawater is assumed to perform this duty in a coastal location. For the conventional coal power station, almost no fresh water is consumed at a coastal location, but the water use is significantly higher

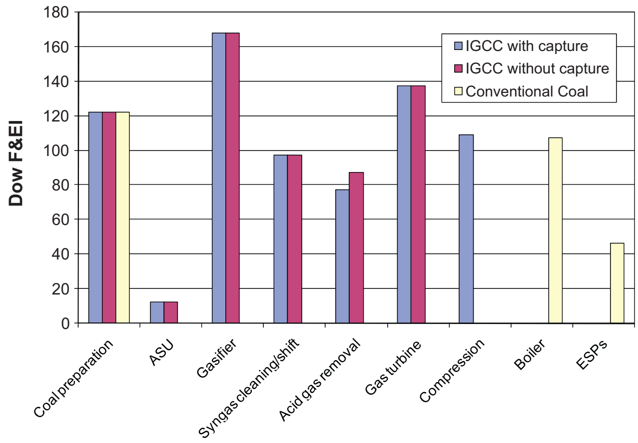

Fig. 7 – The Dow fire and explosion index for the different zones within each process.

at an inland site. Despite the recycle of condensate from the syngas, IGCC always has higher water requirements due to the water used in the quench gasifier and shift reactor, and the recirculated cooling water required for synthesis gas cooling. It is assumed that seawater cannot be used for this duty, because of the toxicity of the syngas, and the safety and environmental risk that a tube leak would pose. Coal consumption is the same for all three processes, but the differing depletion rates in Fig. 6a reflect the differing net efficiencies of the three processes.

Fig. 6b shows the lower emissions in tonnes per MWh, but these are not to be considered less important. SO_2 and NO_x are considered for their acidification potential and NO_x as a precursor in the formation of photochemical smog, and for these categories the IGCC processes have almost no emissions. Unlike a conventional power station which oxidizes the sulfur and nitrogen to produce SO_x and NO_x, in IGCC processes the sulfur and nitrogen are reduced to H_2S and NH_3 in the gasifier and both can be removed from the tail gas stream. There also exists the potential to capture both as useful products; however, in this study it has been assumed that recovery is not commercially viable and that both compounds are dissolved in the wastewater, which results in greater emissions of sulfates and nitrates from the IGCC processes. In the case of solid waste, the slag from the gasifier has market value as a cement additive and does not contribute to landfill. Therefore the only significant solid waste is the ash which is significantly higher in a conventional power station.

4.4. *Inherent safety assessment*

As a measure of inherent process safety for the three cases, the fire and explosion index (F&EI) is reported for each zone in Fig. 7. Since the coal consumption rate is the same, the F&EIs for the coal preparation areas are identical. Cases B and C possess the same inherent risks through much of their processes, and these cases only differ with regard to CO_2 compression and acid gas capture. The gasifier has the largest F&EI, which is significantly greater than the conventional coal boiler. It is assumed that no hydrocarbon refrigerants are used in the ASU and the only flammable liquids are seal oil and lubricating oils. The gas turbine has the second largest F&EI, and again this is not present in the conventional plant.

5. Discussion

The gross thermal efficiencies calculated for Cases B and C are 42.1% and 40%, respectively, based upon the lower heating value of the coal. This is somewhat lower than values quoted in the literature for IGCC with and without capture. For example the (IEA GHG, 2003) report gives gross efficiencies for a Shell gasifier with full heat recovery for no capture and capture of 48% and 45%, respectively, and a Texaco quench entrained-flow gasifier gives gross efficiencies of 44% and 42%, respectively. A 2%pts difference in the gross efficiencies for the quench systems may be attributed to the lower ambient temperature, 9 °C, in the IEA report compared with Australian summer temperatures of 25 °C—affecting the efficiency of the gas turbine. A further 4%pts reduction in the gross thermal efficiency is attributed to the choice of a quench entrained-flow gasifier over the more expensive gasifier with full heat recovery.

The net efficiency for Case B is 32.1% (LHV) and this is also low compared with the IEA report, where the Shell and Texaco gasifiers had net efficiencies of 43.1% and 38.0%, respectively. The proportion of the gross power consumed by the air separation unit for the Shell and Texaco gasifiers were 11% and 12%, respectively, compared with 18% in this study. The higher ambient temperature would increase the power requirement for the ASU significantly. Furthermore, 50% integration between the gas turbine and ASU, as was considered in the IEA study, would also account for some of this difference, but Rieger et al. (2008) reported an improvement of only 0.5%pts in the overall IGCC efficiency from the close integration of these two units, and this is at the expense of operational reliability and stability, and was not considered in this report for that reason.

The difference between the net efficiencies of the with- and without-capture cases is referred to as the carbon capture penalty. The energy penalty is related to the energy required to shift the synthesis gas from CO to CO_2, to pump and regenerate the solvent used to absorb the CO_2, and to compress and dry the CO_2. In the IEA report, the capture penalties for the Shell and Texaco gasifiers were 8.6 and 6.5%pts, respectively, compared with 6.0%pts in this study. The lower capture penalties for both the Texaco case and the cases considered in this study (both of which are quench gasifier systems) are caused by the fact that the water introduced for the quench provides sufficient excess for water gas shift. In the Shell gasifier with full heat recovery, additional steam is drawn from the power cycle and added to the syngas at the shift reactor, and the excess is ultimately condensed in the synthesis gas coolers at an energy penalty. This means that the more favourable capture penalty associated with the quench gasifier is offset by the less favourable gross efficiency.

The capture penalty of only 6%pts for IGCC is a much smaller penalty when compared with the typical values of 10%pts for post-combustion capture from conventional black coal power generation (Metz et al., 2005), or 25% loss of output (Herzog, 2010) which for the reference case corresponds to a similar reduction in efficiency. This lower capture penalty has provided a strong argument for IGCC with capture in the literature, but any advantage of IGCC is lost, if the overall efficiency is not higher than conventional coal with post-combustion capture. This work suggests that conventional coal with post-combustion capture would have efficiencies of around 28% compared with only 26% for IGCC with capture.

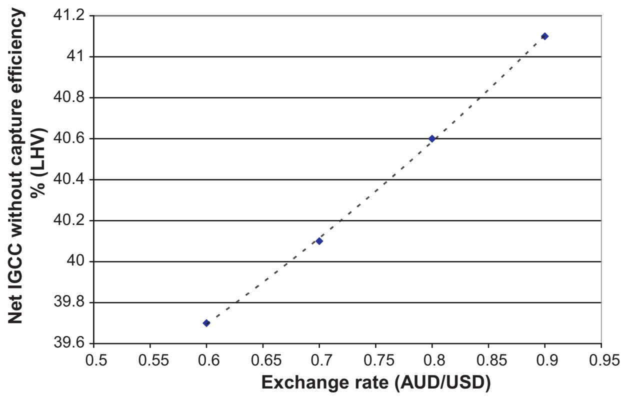

Fig. 8 – The required efficiency for IGCC without capture to match the selling price for conventional coal electricity as a function of the AUD/USD exchange rate.

The capital costs for the two IGCC options are significantly greater than the reference case, Case A. Fig. 4 shows Case A at AUD4200/kW of net capacity, compared with AUD5100/kW and AUD7500/kW, for Cases B and C, respectively. The IGCC costs appear to be significantly higher than those estimated by Rubin et al. (2007) for IGCC with and without CCS and this might be due to recent cost escalation or a much more expensive gasifier design. The cost of the gasifier unit alone is similar to the cost of the conventional power station, and the gas turbine and HRSG cost only 20% less than a conventional boiler. The capital cost of the capture plant is also very significant. It is necessary to consider whether the scale of the proposed IGCC process is too small to be competitive. The 500 MW gasifier is larger than any gasifier currently in operation, and most other studies, including the IEA report, indicate that two 50% gasifiers are preferred. Furthermore, the maximum achievable scale for conventional power stations is now 800 MW, putting IGCC at further disadvantage.

The total operating costs in Fig. 5 of AUD43/MWh, AUD57/MWh and AUD82/MWh and all of the four major components of the operating costs increase in absolute terms when moving from conventional coal to the two IGCC processes. As a result, the minimum electricity prices for a return of 7% over 20 years at an AUD/USD exchange rate of 0.7 are USD80 MWh^{-1} (AUD115 MWh^{-1}), USD101 MWh^{-1} (AUD144 MWh^{-1}) and USD145 MWh^{-1} (AUD207 MWh^{-1}), for Cases A, B and C, respectively.

Case B could not compete with conventional power as represented by Case A, nor could it gain idealistic support, because its lower efficiency is not offset by a reduction in greenhouse gas emissions. However, as a relatively new technology, further improvements in efficiency are likely. Fig. 8 gives the net thermal efficiency that would be required in Case B to enable it to be economically competitive with Case A. This turns out to be a strong function of the AUD/USD exchange rate, where these required efficiencies (39–41%) are not unrealistic, and it is conceivable that IGCC without capture can become competitive with conventional coal in the future.

Fig. 6 summarises the resources consumed and the emissions per unit electricity sent out. An interesting feature is the significantly higher water consumption for the two IGCC processes compared with conventional coal. Even for an inland location where a conventional power plant is consuming water to condense steam, Cases B and C have 18% and 107% higher water use. The reason for this is the greater waste heat

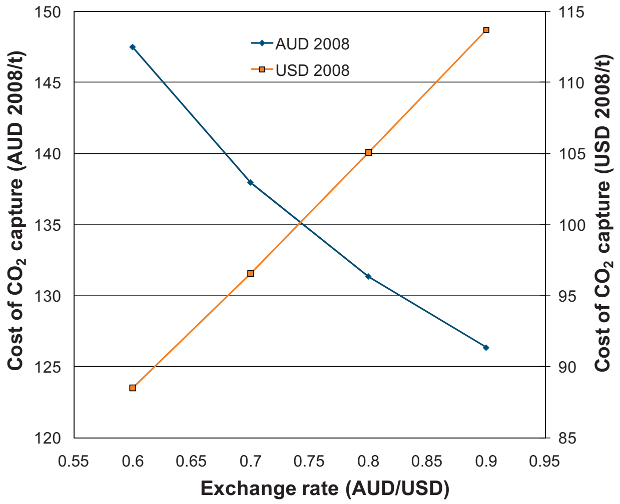

Fig. 9 – The cost differential per tonne of CO_2 emitted as a function of the AUD/USD exchange rate.

generated in the IGCC processes, because the synthesis gas must be cooled to close to ambient temperature prior to H_2S removal (Case B) and CO_2 removal (Case C). Ideally this waste heat would be recovered, but the heat integration analyses shown in Fig. 2 indicate that the process pinch point was around 180 °C for both IGCC cases and therefore the waste heat is of relatively low value. The other interesting result from the life cycle inventory analysis is the transfer of SO_x and NO_x emitted to air from the conventional power station to nitrates and sulphates emitted in the wastewater of the IGCC processes. It is not possible to draw a conclusion as to which is preferred, as this depends on local factors, such as the prevailing wind, the size and health of the receiving waterway, and the proximity to population centres.

In Fig. 9 the net cost of capturing the CO_2 has been calculated by comparing the electricity selling price for Case C to that of the selling price of the conventional power station Case A. Applying Eq. (1), this cost difference is also adjusted by considering the difference in CO_2 emission intensity of the two cases; where for Case C, 80% of the CO_2 is captured. The net cost of capture is plotted in Fig. 9 as a function of the AUD/USD exchange rate. A charge of around USD100/tonne of CO_2 is required before Case C becomes competitive with conventional coal (Case A). Any cost incurred in the transmission and storage of the CO_2 for Case C would add directly to this equalizing charge, so that if the transmission and storage cost was USD10/tonne, then it would increase to USD110/tonne.

The final assessment of the IGCC process is made with regard to its relative inherent safety, by making use of the Dow F&EI. Apart from the coal preparation area, the comparative zones associated with IGCC all possess higher inherent risks. This is because of the high pressures and high temperatures of the IGCC process and the fact that the synthesis gas is always within the flammable range. It should be noted that in the calculation, the maximum credit has been allowed for the preventative and mitigating systems used in typical hazardous facilities, such as computer monitoring and alarms, emergency isolation and depressurization, gas detection, fire sprinkler systems, fire fighting systems, and operational procedures and training. There are costs for requiring such systems, which have also been included in the economic assessment. It is not just the magnitude of the risks associated with the IGCC process, but it is also the number of hazardous zones; whereas conventional coal has three zones, (viz., the coal preparation, the boiler and the flue gas cleanup), Cases B and C have six and seven zones, respectively, which increases process complexity and increases the probability of a safety incident.

The F&EI, as its name suggests, is concerned primarily with fire and explosion hazards which lead to the calculation of a damage factor and plant outage. Although the index applies additional penalties for toxicity, it does not properly consider toxicity risks with regard to either small fugitive emissions, or larger losses of containment of toxic material that may not pose a direct fire or explosion hazard. Throughout most of the process plant, carbon monoxide is present at concentrations several thousand times higher than TWA limit, so even a minor loss of containment poses a health risk to personnel onsite, while a major loss of containment potentially poses a hazard to the general public. Similarly the supercritical storage gas stream has the potential to cause a vapour cloud of asphyxiating (CO_2) and toxic (H_2S) gas which could affect neighbours at lower elevations. The high pressures, temperatures and flammable gases throughout the site increase the risk that a single incident could set off a chain reaction of incidents. Overall, the inherent safety risks associated with IGCC-CCS are much higher than for a conventional coal power station, with or without post-combustion capture.

6. Conclusions

The following conclusions can be made from this study which was based on comparing combined cycle electricity production from an oxygen-blown entrained-flow gasifier with a water quench without and with CCS, to a conventional supercritical power station burning the same Queensland black coal:

- The IGCC without capture has a lower net efficiency (32%) compared to conventional pulverized coal power generation (37%); at the same time IGCC without capture incurs higher capital and operating costs.
- Despite the smaller energy penalty of 6%pts for CO_2 capture, IGCC-CCS does not appear to have a significant efficiency advantage over conventional coal-fired power generation with post-combustion capture.
- IGCC has considerably higher water demands than conventional coal power generation for both inland and coastal locations.
- The IGCC process does considerably reduce the atmospheric emissions of SO_x and NO_x. However, this is done by transferring the environmental burden to the wastewater system which leads to significantly higher levels of NO_3^- and SO_4^{2-}, which could have environmental consequences depending on the nature of the receiving waterway.
- The risk associated with fire and explosion is increased in probability due to the increased number of process units, and in severity due to the process conditions and gas compositions in many parts of the IGCC process.
- Risk associated with toxicity are almost nil in a conventional modern power station, but are significant in an IGCC process due to high concentrations of CO and H_2S.
- The cost differential between the conventional plant and the IGCC-CCS plant is around USD100/tonne CO_2.

Although this study did not investigate the economics of alternative clean coal technology processes, IGCC presently appears to be relatively expensive due to its high capital cost and on-going capital charges.

It is concluded that the application of IGCC-CCS as clean coal technology is highly effective in reducing carbon dioxide emissions, the highest-profile problem currently associated with coal-fired electricity generation. There is an economic penalty which may be overcome, if the net efficiency of the process (prior to CO_2 capture) could be increased by about 8%pts, or less if the capital cost is reduced. Technology advances are likely to reduce this gap over time.

Overall, the inherent safety risks associated with IGCC-CCS are much higher than for a conventional coal power station, with or without post-combustion capture. This conclusion is not intended to imply that the facility cannot be designed and operated in a manner which reduces and mitigates this risk to a level acceptable to the industry and to the regulators; rather, it is intended to emphasise the additional challenges that an IGCC-CCS facility would face in areas of risk reduction, risk mitigation and public relations, and raise an open question about whether these challenges would be sufficient to deter potential operators from IGCC-CCS technology in favour of an inherently safer alternative. This and environmental factors, such as water consumption, have until now been under emphasized.

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