Canadian Clean Power Coalition (CCPC) Phase II Summary Report

Prepared by

CCPC Technical Committee

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FINAL VERSION

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A) INTRODUCTION

The Canadian Clean Power Coalition was created in 2000 to protect and enhance Canada's vast coal and other carbon-based resource wealth and to ensure that environmental public policy decisions recognized that these resources are a Canadian asset, not an environmental liability.

Phase I was initiated in 2001 to develop the next generation of coal power technology, leading to one or more demonstration projects. During Phase I, coal-fired power generation technology options that could control all emissions, including CO_2, were assessed. A number of detailed engineering design studies showed that:

- Technology is commercially available to control conventional air emissions (NOx, SOx, particulates, mercury) from Rankine cycle power plants to levels approaching that of natural gas power generation.
- Gasification processes for sub-bituminous coal and lignite are not yet fully commercial, and require significant development to attain the required availability levels.
- Ongoing developments of amine scrubbing processes have achieved substantial improvements in energy efficiency. Further refinements are possible and need to be compared with other processes to optimize the process selection.
- The Western Sedimentary Basin provides storage capacity for a vast amount of CO_2 in B.C., Alberta and Saskatchewan. Storage opportunities and capacities for the Ontario and Maritime regions are less well understood.

However, costs for many of these technologies were high and, particularly for the use of gasification of low rank western Canadian coals, much remains to be done to achieve optimized, cost effective designs. While Phase I took a high-level approach to identify appropriate technologies and benchmark their performance capabilities, Phase II sought to improve on that knowledge through the detailed study of the most attractive technologies to obtain the necessary improvements in performance and cost. As such, the gasification technologies selected were next generation technologies that are not commercially available today.

CCPC's membership for Phase II was made up of the following companies: ATCO Power, Basin Electric Power Cooperative, EPCOR, Electric Power Research Institute (EPRI), Sherritt, Nova Scotia Power, SaskPower, TransAlta. Support and additional research funding for Phase II has come from Alberta Energy Research Institute (AERI) and Natural Resources Canada (NRCan).

Phase II was initiated in 2004 and was completed in 2007. Two major work packages were completed for Phase II:

- Supercritical Pulverized Coal (SCPC) Plants with CO_2 Capture - This work package assessed both amine scrubbing and oxyfuel combustion processes.

- Gasification Technology Optimization
  - Stage 1 - Assessed gasification technologies that were more suitable for low rank coals.
  - Stage 2 - Assessed feedstock beneficiation/blending as well as optimum blend of electrical power and hydrogen that could prove out the value of gasification.

The assumptions used in economic models for both studies were:

- CO_2 sales and CO_2 offset costs were included
- Transmission costs were added
- Parasitic loads were included versus power purchases for parasitic loads
- Added \$70 million CO_2 pipe for CO_2 sales
- Added \$200 million H_2 pipe for H_2 sales
- Added property tax and insurance
- Removed GST costs (as GST is netted out by companies)
- Sub-bituminous coal price was \$1.25/GJ, lignite coal price was \$1.50/GJ in 2013
- Capacity factor was 60% for all CO_2 capture cases in first year, 85% for remainder
- Tax rate was 30%
- Return on equity was 15%
- Split H_2 price 50/50 Firm/Non-Firm at \$2,000 per tonne and \$1,000 per tonne

B) <u>SUPERCRITICAL PULVERIZED COAL PLANTS WITH CO_2 CAPTURE</u>

This work package conducted a technical and economic review of post-combustion and oxyfuel based CO_2 capture technologies using bituminous, sub-bituminous, and lignite coals.

Design Basis

The 11 options studied were:

<u>Sub-Bituminous Coal</u>
C1-R0: Keephills Base Case Plant (no CO_2 capture)
C1-A1 Keephills Oxyfuel Plant (oxyfuel based CO_2 capture)
C1-A2 Keephills Retrofitted Oxyfuel Plant (oxyfuel based CO_2 capture)
C1-B1 Keephills Post Combustion (Amine Scrubbing based CO_2 capture)
C1-B2 Keephills Retrofitted Post Combustion (Amine Scrubbing CO_2 capture)

<u>Bituminous Coal</u>
C2-R0: Pt. Tupper Base Case Plant (no CO_2 capture)
C2-A1 Pt. Tupper Oxyfuel Plant (oxyfuel based CO_2 capture)
C2-B1 Pt. Tupper Post Combustion (Amine Scrubbing based CO_2 capture)

<u>Lignite Coal</u>
C3-R0: Shand Base Case Plant (no CO_2 capture)
C3-A1 Shand Oxyfuel Plant (oxyfuel based CO_2 capture)
C3-B1 Shand Post Combustion (Amine Scrubbing based CO_2 capture)

All CO_2 capture power plant options in this project have been designed to achieve approximately 90% CO_2 capture rate and conform to all other emission targets specified by CCPC for this project.

Process Descriptions

Consortium partners DoosanBabcock, Alstom Power, Mitsubishi Heavy Industries (MHI), and Air Products, provided technical and capital cost data for the boiler, turbine generator, air separation unit (ASU), amine scrubbing plant, and CO_2 compression plant for all options being studied. They also provided data for the DeHg system, FGD unit, and $DeNO_x$ system for selected options. Information from the consortium partners (as shown in Table 1) was combined with data developed in this study to completely define the plants under review.

Table 1 – Scope of Supply

	Reference Plant	Oxyfuel	Amine Scrubbing
Boiler Island	DoosanBabcock	DoosanBabcock	DoosanBabcock
Steam Turbine Island	Alstom Power	Alstom Power	Alstom Power
FGD	MHI	Not Required	MHI
ASU	--	Air Products	--
Amine Scrubbing (KS-1 process)	--	--	MHI
CO_2 Cleanup & Compression	--	Air Products	MHI

Neill & Gunter provided the “balance of plant” designs and cost estimates, as well as rolling up the overall plant cost estimates. Costs were ± 30% and fourth quarter 2007 timeframe. The currency exchange rates used were:

- $1.00 US = $1.15 CAN
- 1.00 € = $1.50 CAN
- 1.00 £ = $2.20 CAN

Within this project, all power plant options are based on advanced supercritical pulverized coal (SCPC) boiler/turbine technology state-of-the-art steam turbine inlet conditions of 290 bara/ 600°C (HP) and 620°C reheat (IP). All designs are on the basis that proven technologies be employed wherever possible and appropriate. For the convenience of benchmarking the various CO_2 capture technology options, the performance design and evaluation of each power plant option are based on assuming the same fuel heat input rate as that of the reference power plant case, R0 which is approximately 500 MWe (net).

MHI’s flue gas CO_2 recovery plant utilizes the KS-1 solvent as the CO_2 absorbent, which is a sterically hindered amine developed through the cooperation of KANSAI and MHI. The process is based on commercially proven highly advanced technologies, capable of recovering CO_2 from flue gases under various conditions. Application of this process will lead to lower energy consumption and extended solvent life in comparison to other amine-based type processes. This process will provide higher level of advanced performance than its predecessors, making CO_2 recovery more feasible due to the reduction of steam consumption by 30% compared to conventional MEA processes by utilizing the heat of the CO_2 lean KS-1 solvent for solvent regeneration effectively.

Air Products has proposed an innovative CO_2 compression and clean up system that can also remove SO_2, NO_x and mercury. The process details are confidential. This technology is only in the design stage; it has yet to be proven in a pilot plant, but appears promising.

The block diagrams for the oxyfuel process and amine scrubbing process are shown in Figures 1 and 2.

Figure 1 – SCPC Oxyfuel Block Diagram

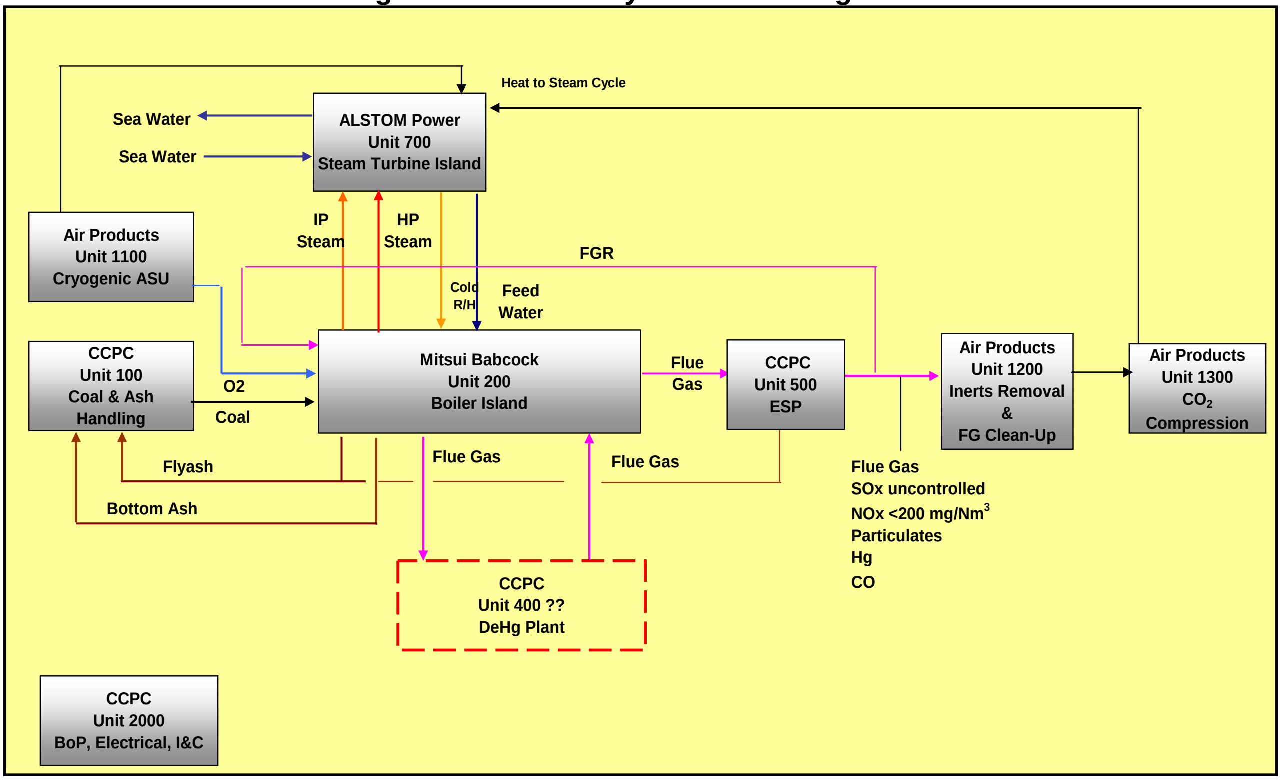
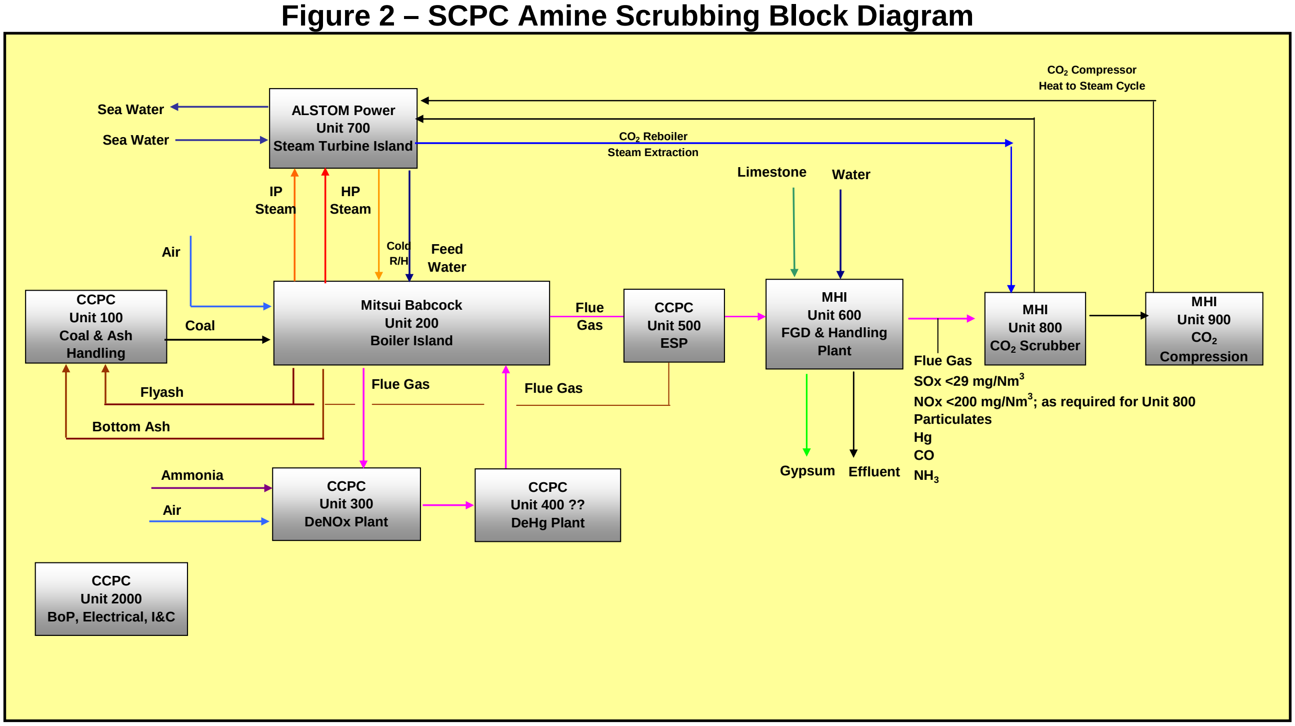


Figure 2 – SCPC Amine Scrubbing Block Diagram



Performance and Cost Summary

Table 2 gives key cost and performance values for all study options. The table shows the proposed technologies can achieve a CO_2 capture rate of approximately 90 percent. However, a significant plant efficiency penalty, of up to 10 percentage points, is associated with CO_2 capture for both oxyfuel and post combustion capture methods. The significant impact a CO_2 capture system has on a plant is clearly shown in the large increases in capital cost and huge parasitic power demands for the A1, A2, B1, and B2 cases. The oxyfuel capital costs were found to be higher than amine scrubbing plants, but their O&M costs are estimated to be 6 percent to 15 percent less, and they are more effective capturing $CO_{2.}$ This can be important if there is a market for the captured gas.

Table 2 also shows the Keephills oxyfuel option as slightly more cost effective than amine scrubbing, largely because of C1-A1's lack of a FGD plant. For the Pt. Tupper and Shand sites, which require FGD systems for all options, the amine scrubbing plants were found to be slightly less expensive than oxyfuel. As expected the retrofitted options were more expensive than non-retrofitted plants. This is especially true for the oxyfuel retrofit which is by far the most expensive alternative since it carries the cost of significant boiler and boiler house modifications as well as the ASU plant. Except for the costly C1-A2 case, all capture options were found to have similar lifecycle costs, well within the accuracy level of the study.

Compared to the reference power plant C1-R0 without CO_2 capture, for the main project design fuel C1 Sub-bituminous coal, the reduction in cycle efficiency of the oxyfuel CO_2 capture power plant option C1-A1 is estimated to be approximately 8.8% points (HHV basis).

The relative reductions in cycle efficiency of the oxyfuel CO_2 capture power plant for the three coals/sites are approximately 9.0% points on HHV basis despite the different coal/site conditions.

The cost of the retrofit oxyfuel CO_2 capture plant (C1-A2) is higher than other options is also partly due to the higher O&M costs for a retrofitted plant due to the less efficient cooling system and the need to operate an existing FGD plant not present in the C1-A1 oxyfuel capture case. The low sulphur content in the C1 coal does not necessitate a FGD plant within the boiler island.

Note that the retrofit option of C1-A2 indicates approximately 1% point more efficiency penalty than that of the greenfield option C1-A1. This is caused by a plant restriction of constraining the cooling water mass flow rate by approximately 20% less than that of C1-A1. With this cooling water restriction, it was estimated that the increase in condenser heat rejection combined with the additional cooling water requirements elsewhere would increase the condenser pressure by some 1.0 kPa at average ambient conditions (i.e. 5.0 kPa instead of 4.0 kPa). Supplementing the main cooling water system pumps of the cooling tower (and using less adiabatic compression) would negate this plant efficiency penalty.

The CO_2 price uses the concept of "break-even" (BE) price instead of cost of capture or avoided cost. Also included for comparison purposes are both the cost of capture and avoided costs. The break even cost of CO_2 was determined by driving up the credit price until the first year cost of power for a reference coal plant without capture equals the first year cost of power for the carbon capture plant. When the price of CO_2 credits are below the BE price, one would build SCPC and buy CO_2 credits. When the price of CO_2 credits is above the BE price, one would build a plant with CO_2 capture. It is assumed that projects with CCS which meet the CCS intensity requirements post 2018 will not be able to sell CO_2 credits.

The first year cost of power was determined by finding the first year power price, escalating by 2% each year, which sets the NPV of the project equal to zero. By definition when the NPV of a project is zero, the NPV of the revenue equals the NPV for the costs. This price profile can be compared to a nominal power price forecast.

The study concludes the BE cost of CO_2 is approximately $77 to $101 per tonne depending on the capture technology used, coal characteristics, plant site configuration, and for a new facility.

The first year cost of electricity (COE) is shown in Table 3 and is broken down into various components. CO_2 capture increases the COE for new facilities from between 42% to 56% depending on the coal and CO_2 capture technology. These numbers already include selling 50% of the CO_2 for enhanced oil recovery (at $42 per tonne).

Given the study level of accuracy, the developed costs are too similar to indicate an overall economic preference for either capture method. To clearly recommend a preferred capture technology, more detailed work is needed to identify the advantages, disadvantages, and costs of each available option based on a specific site design.

Table 2	**Summary of Costs and Plant Performance**										
OPTION	**C1-R0**	**C1-A1**	**C1-A2**	**C1-B1**	**C1-B2**	**C2-R0**	**C2-A1**	**C2-B1**	**C3-R0**	**C3-A1**	**C3-B1**
Coal Feed (Wet) (t/h)	226	226	226	226	226	129	129	129	303	303	303
Gross Plant Output (MW)	542.0	570.5	568.7	480.5	484.1	546.4	568.1	490.7	542.0	580.0	479.2
Net Plant Output (MW)	503.4	400.2	392.3	391.3	394.1	510.5	413.2	409.9	499.5	397.5	382.0
Plant Efficiency (%) (HHV)	42.9	34.1	33.4	33.4	33.6	44.5	36.0	35.7	39.7	31.6	30.3
Total Plant Cost ($ x 10^6)	$1,522	$2,121	$2,500	$2,028	$2,020	$1,351	$2,063	$1,784	$1,459	$2,284	$1,927
Total Plant Cost ($/kW)	$3,024	$5,300	$6,373	$5,182	$5,125	$2,645	$4,993	$4,352	$2,921	$5,746	$5,044
Total Capital Req'mt ($ x 10^6)	$1,832	$2,652	$3,108	$2,539	$2,530	$1,626	$2,582	$2,246	$1,844	$2,990	$2,539
Total Capital Req'mt ($/kW)	$3,640	$6,626	$7,923	$6,489	$6,418	$3,184	$6,248	$5,478	$3,691	$7,524	$6,645
First Year Cost of Power ($/MWh)	$88.3	$130.0	$152.7	$131.3	$128.8	$92.0	$140.9	$130.4	$97.7	$154.5	$143.3
Break-Even Cost of CO_2 ($/t)	--	$77	$94	$81	$66	--	$101	$83	--	$91	$78
Capture Cost of CO_2 ($/t)	--	$70	$97	$72	$71	--	$88	$75	--	$81	$69
Avoided Cost of CO_2 ($/t)	--	$75	$113	$80	$79	--	$98	$81	--	$90	$78
CO_2 Capture Rate (%)	--	90	89	87	87	--	89	88	--	89	87
CO_2 Emission Intensity (t/MWh)	0.79	0.10	0.11	0.13	0.13	0.68	0.09	0.11	0.88	0.12	0.16
Heat Rejection / Flue Gas Discharge	Natural Draft Cooling Tower					Sea Water Cooling / Stack			Natural Draft Cooling Tower		

Table 3	First Year Cost of Electricity ($ per MWh in 2013)										
	C1-R0	**C1-A1**	**C1-A2**	**C1-B1**	**C1-B2**	**C2-R0**	**C2-A1**	**C2-B1**	**C3-R0**	**C3-A1**	**C3-B1**
CO_2 EOR Commodity Sales	--	-12.1	-12.2	-12.0	-11.9	--	-10.2	-10.1	--	-13.4	-13.5
CO_2 EOR Offset Sales	--	-6.7	-6.8	-6.7	-6.6	--	-5.7	-5.6	--	-7.4	-7.5
Sequestered Offset Value	--	-6.7	-6.8	-6.7	-6.6	--	-5.7	-5.6	--	-7.4	-7.5
CO_2 Disposal Cost	--	1.6	1.6	1.6	1.6	--	1.4	1.3	--	1.8	1.8
CO_2 Offset Cost	5.0	8.4	6.5	8.5	6.5	3.4	6.2	6.2	6.4	10.0	10.4
Coal Costs	10.6	13.5	13.7	13.8	13.7	24.2	30.0	30.3	13.7	17.4	18.1
Transmission	4.0	5.1	5.2	5.2	5.1	3.9	4.9	4.9	4.0	5.1	5.3
O&M and Other	8.1	12.3	14.3	15.2	15.9	7.5	11.7	14.1	12.1	18.3	21.2
Equity Return	30.3	57.4	68.7	56.2	55.6	26.5	54.2	47.5	30.8	65.2	57.6
Debt	22.0	41.6	49.7	40.7	40.3	19.2	39.2	34.4	22.3	47.2	41.7
Working Capital	0.6	0.8	0.8	0.7	0.7	0.5	0.6	0.5	0.5	0.7	0.6
Taxes	7.6	14.9	18.0	14.6	14.4	6.7	14.2	12.4	7.9	17.1	15.1
Total Cost	**88.3**	**130.0**	**152.7**	**131.3**	**128.8**	**92.0**	**140.9**	**130.4**	**97.7**	**154.5**	**143.3**

C) DISCUSSION OF RESULTS FOR SUPERCRITICAL PULVERIZED COAL PLANTS

An oxyfuel boiler recycles flue gas to dilute the oxygen (ranging from 65 %~70% of the main flue gas at boiler outlet). This results in an increased concentration of sulphur and chloride components of flue gas, hence increasing acid corrosion risk to the boiler island components exposed to the flue gases.

While the configurations of the oxyfuel CO_2 capture power plant may vary depending on the coal/site conditions, the oxyfuel boiler island configurations may vary depending on the key components of the coal fired, primarily the sulphur content which relates to furnace corrosion design constraints. With respect to the three different design coals for this project, three slightly different oxyfuel power plant configurations have been adapted for each coal/site, with configurations differences mainly in the employment of either a FGD plant or a flue gas Direct Contact Cooler (DCC) for the flue gas recycle (FGR) streams.

Conclusions

The conclusions drawn based on the technical and economic analysis results are as follows:

Technical

1. Compared to a reference power plant without CO_2 capture, for a nominal 400 MWe (net) SCPC power plant with 90% CO_2 capture rate, the thermal efficiency loss due to CO_2 capture is approximately 8.0 ~ 9.5% points (HHV basis).
2. The relative thermal efficiency penalty due to CO_2 capture using oxyfuel and amine CO_2 capture technologies are comparable with variation of approximately 1% point.
3. For the project main design coal C1:Sub-bituminous, the optimized oxyfuel CO_2 capture power plant C1-A1 thermal efficiency is approximately 1% point higher than that of the amine CO_2 capture power plant C1-B1 option.
4. Compared to the optimized oxyfuel CO_2 capture power plant C1-A1, C1-A2 as a retrofit from non-capture ready C1-R0 reference, retains the SCR and FGD plants and full air-firing capability, with thermal efficiency comparable to that of amine Scrubbing case C1-B1.
5. For C2: Bituminous cases, the power plant thermal efficiency for oxyfuel and amine scrubbing CO_2 capture option are comparable, with similar efficiency penalty of approximately 8.5~8.8% points (HHV).
6. For C3: Lignite cases, the power plant thermal efficiency penalty for oxyfuel is approximately 8% points, which is approximately 1% point less than that of amine scrubbing option.

Economics

7. The break even CO_2 cost and electricity cost are very much comparable between the oxyfuel CO_2 capture option C1-A1 and the amine scrubbing CO_2 capture option C1-B1.
8. The oxyfuel CO_2 capture option C1-A1 has marginally higher thermal efficiency and lower levelized cost than the C1-B1 amine scrubbing option.

Overall

This study:

- Established overall CO_2 capture power plant designs and process integration built on knowledge and experience of proven conventional air/PC firing power plants.
- Developed conceptual designs and layout for new-build CO_2 capture and CO_2 capture-retrofit PF-fired supercritical power plant based on both amine scrubbing and oxyfuel CO_2 capture technology, targeting near-term market, on proven technology for minimum risk.
- Established the sensitivity to technical performance of the CO_2 capture technology considered for three different Canadian coal / sites.
- CO_2 capture and CO_2 capture-ready power plant emissions and waste streams are within the agreed design targets.
- Confirmed technically feasible to “retrofit” carbon capture technology to a coal-fired power plant using either oxyfuel technology or amine scrubbing technology
- Achieved capture plant performance with CO_2 emissions capture level up to 90%.
- Optimised plant performance through process integration with consideration of practical plant flexibility and reliability, availability and maintainability.

The principal equipment development requirements leading to possible demonstration of the CO_2 capture technologies are outlined below.

Boiler Island: Oxyfuel

- Demonstration of a utility boiler full scale oxyfuel burner / combustion system.

Steam Turbine Island: Amine

- The 60Hz market power requirements has stretched the steam turbine aero-mechanical technology to the point where LP turbine efficiency has been compromised for cases where condenser pressure is low due to low ambient cooling water temperatures. Turbine expansion is increased within a flow-path flow area, constrained by blade mechanics, resulting in performance loss due to excessive flow Mach number.

Balance of Power Plant: Oxyfuel & Amine

The following are the major issues identified to have significant technical and/or economic impact to a future CO_2 capture power plant.

- Integration of technologies into the power plant and between each sub-system (i.e. turbine is the main driver for amine, flue gas conditioning for oxyfuel). This may include determining the flexibility of boiler and turbine designs to accommodate better integration and efficiencies, while still providing the reliability and performance expected from a power plant
- Review of auxiliary power requirements (associated with integration). There is a major power penalty whichever CO_2 capture system is utilized and more design review between the different partners is required to more accurately identify penalties, while optimizing overall plant integration.
- Real site layout considerations should be used to facilitate more accurate capital costing.
- Defining, if possible standardized purity requirements for captured CO_2, which would depend on the use or disposal point for the CO_2 (i.e. EOR, or sequestration) and the impact purity would have on capture costs. This can significantly affect costs. It is not known if there is one standard for EOR, CBM or sequestration which is applicable for all

locations. The maximum concentrations of certain contaminants, such as H_2S, may also be limited by the ability to permit the CO_2 pipeline depending on the route and population densities.

ASU & CO_2 Compression Plant: Oxyfuel

- There is a need for a demonstration of the oxyfuel CO_2 capture purification and compression stages of the oxyfuel technology, from the direct contact cooler to the compressed, purified CO_2 product. Although based on known technology, demonstration at about 1 MWt scale is recommended to allow the expected performance to be validated. Such a 1MWt pilot plant would also allow quantification of unknowns, such as the fate of impurities in the raw flue gas.
- There is much to be gained from looking at the optimization of the CO_2 compression system. In this study, Air Products has used adiabatic compression extensively with heat being recovered to the steam cycle. This may not be the best overall solution, especially in cases where cooling water is restricted. There may also be ways to utilize the fact that above its critical pressure CO_2 can be pumped. This could be combined with compression to lower the overall power consumption.
- Air Products have been working to improve the power consumption of capture rate of the CO_2 purification system and have cycles that increase recovery of CO_2 to above 97% without increasing power consumption. Also, they have been working on cycles that could efficiently either produce the CO_2 as a liquid product for tanker transportation or could be combined with CO_2 pumping to reduce the overall power consumption, as mentioned above.
- Air Products is developing their Ion Transport Membrane (ITM) technology. A study of the oxyfuel conversion of boilers and heaters on a refinery site using an ITM Oxygen system to produce the oxygen showed that, when integrated into the current steam system, the ITM Oxygen system resulted in a cost of CO_2 capture around half that of the traditional cryogenic ASU.

MHI Process: Amine

- Flexibility issues: Effective integration of amine systems with power plants is becoming reasonably well understood for baseload conditions. Considerations for post-combustion capture to lend itself to flexible operation in order to follow electric system load requirements. A number of areas that need to be addressed, in an interlinked way, to assess the practicability and desirability of implementing such flexible approaches are:
    - amine plant performance mapping over a wide range of operating conditions;
    - amine behaviour during storage;
- Realistic solvent testing: Large-scale, long-term solvent testing on real coal flue gases might be an area of common interest, but difficulties arise due to the need to accurately assess coal and plant specific effects on flue gas composition and hence solvent chemistry changes in the long term.

D) GASIFICATION TECHNOLOGY OPTIMIZATION – STAGE 1

A variety of gasification technologies and process configurations were evaluated by Jacobs for processing of either lignite coal or sub-bituminous coal to produce a syngas fuel suitable for powering a gas turbine.

Selection of Plant Configurations

After the Recommended Approach Report was issued by Jacobs the following plant configurations were selected for further consideration in Stage 1 of the study.

- Lignite Coal
  - Case 1 - CO_2 Capture Case
  - Case 2 - CO_2 Capture Ready Case
  - Case 3 - No Shift / No CO_2 Capture)
- Sub-bituminous Coal
  - Case 4 - CO_2 Capture Case
  - Case 5 - CO_2 Capture Ready Case
  - Case 6 - No Shift / No CO_2 Capture

The design objective for Stage 1 of the project as specified by the CCPC was to configure the plants to have a high efficiency while maintaining cost effectiveness.

Design Basis

This design basis establishes the technical basis for performing Stage 1 of the Gasification Case Optimization Study in which the performance and capital and operating costs of six greenfield IGCC plants were developed. The IGCC plants were configured to gasify sufficient feedstock to feed two GE 7FB gas turbines operating in combined cycle. Two coals were studied, Alberta sub-bituminous and Saskatchewan lignite, each with and without CO_2 capture.

The performance and capital and operating costs of the six greenfield IGCC plants are developed. Integration between the combined cycle plant and the coal gasification unit was optimized.

The two different site locations were studied: Keephills, 70 km west of Edmonton, Alberta for the sub-bituminous coal cases and the Shand site near Estevan, Saskatchewan for the lignite coal case. The design takes into account the two different site locations, meteorological data, feedstock, utilities, feed and product specifications. The IGCC plants are all greenfield, so integration of the plant with existing facilities is minimal. There are no limitations on plot size. Raw water is available, electricity and natural gas are available for start-up, and a connection to the grid is available for electricity export. All cases have zero liquid discharge. All other services and utilities are generated within the plant.

The percentage of CO_2 removal is optimized at a value that may vary depending upon the plant technologies and configuration utilized. However, the CO_2 emissions are not greater than those for a NGCC plant. Therefore the degree of CO_2 capture is in the range of 70-90% of the carbon in the syngas leaving the gasifier high temperature cooling section.

CO_2 production purity must be $\geq$ 95% CO_2, $\leq$ 4% N_2, $\leq$ 5% hydrocarbons, 10 to 200 ppmv H_2S and supplied at the battery limit at 13.8 MPa and $\leq$ 50°C.

The minimum availability target is 85% operating on coal alone. Natural gas is not used as a backup fuel.

It is assumed that the CO_2 produced by the various technology options being investigated will be used for either enhanced oil recovery or coal bed methane recovery, or it will be sequestered.

Process Descriptions

Coal is received on site by truck and is initially stored in a coal pile and subsequently in a covered storage building. Coal from storage is milled and either dried with a steam heated fluidized bed dryer or mixed into a slurry with water, depending on the coal type. The lignite coal is a low rank coal and would form a low solids content slurry. It is therefore used in the "dry feed" gasifier. The sub-bituminous coal has a lower inherent moisture and forms a slurry with a sufficiently high solids content. It is therefore fed to the "slurry feed" gasifier.

In all cases the coal feed is gasified with a sub-stoichiometric amount of O_2 to produce a raw syngas stream consisting primarily of CO and H_2 with some CO_2. The O_2 feed to the gasifier is provided by an air separation unit. The sulphur in the feed is converted primarily to H_2S with a small amount of COS. The inorganic material in the feed is melted and cooled to form slag that is disposed of off site. The lignite cases have a blowdown water stream from the gasifier which is treated and a portion is recycled to the gasifier vessel. The remaining water is sent to the waste water treatment plant which produces a stream suitable for feeding to a demineralised water plant and a stream to be sent to an evaporation pond. The sub-bituminous coal cases use a gasifier which doesn't have a blowdown water stream. Water from slag dewatering is recycled to the slurry preparation system.

In the CO_2 capture and capture ready cases the saturated raw syngas stream from the gasifier is passed through shift reactors where the CO in the stream reacts with the water vapour in the stream to produce H_2 and CO_2. Heat liberated in this section of the plant is used to raise steam to produce power in steam turbines. The 'shifted' syngas stream is then cooled and the water vapour is condensed and recycled to the gasifier. In the capture cases the H_2S and CO_2 in the syngas are then removed in a Selexol® absorption process. In the capture ready cases only H_2S is removed in the Selexol® plant. Acid gas from the H_2S removal process is sent to a Claus sulphur plant to recover the elemental sulphur which can be sold. In the capture cases the CO_2 is compressed, dried and exported.

In the non-capture cases there is no shift section and the saturated raw syngas stream from the gasifier is cooled and sent through a COS hydrolysis unit where it is reacted with water over a catalyst to convert it to CO_2 and H_2S. The H_2S is easier to remove in the Selexol® process. The syngas is then cooled further and the water vapour is condensed and recycled to the gasifier. Heat liberated in this section of the plant is used to raise steam to produce power in steam turbines. The H_2S in the syngas is then removed in a Selexol® absorption process. Acid gas from the H_2S removal process is sent to a Claus sulphur plant to recover the elemental sulphur which can be sold.

The syngas leaving the acid gas removal plant is then fed to the gas turbines. In the lignite cases the syngas pressure is first dropped from 75 bara to 30 bara in a turbo expander. In the sub-bituminous cases the syngas leaving the acid gas removal unit is at around 30 bara, and therefore there is no turbo expander. The syngas stream is then heated and fed as fuel to two GE 7FB gas turbines. Saturated N_2 is added to the gas turbine combustion chamber in order to suppress the flame temperature and reduce NO_X formation. An SCR catalyst is fitted to the exhaust of the gas turbine in order to reduce the NOx concentration to the required level.

Performance and Cost Summary

The overall performance and cost figures for the six gasification options are summarized in Tables 4, 5 and 6 below.

For a given coal, the feed flow rate required is slightly different for each case. This is because the syngas fuel required by the 7FB gas turbine varies depending on the syngas composition and this is different for both of the cases.

The CO_2 capture rate is approximately 74% for sub-bituminous coal and 84% for the lignite coal. For the sub-bituminous coal, this is much lower than the 85% to 90% capture rate for the supercritical pulverized coal plants. For the sub-bituminous case, a two 2 stage shift was used due to the higher methane content in the raw gas. The two stages of shift converted about 93% of the CO to CO_2. For the lignite case, a single stage of shift was used that converted 86% of the CO to CO_2. The other reason for the lower CO_2 capture rate is that some CO had to be left in the syngas to the gas turbine in order to keep the hydrogen content within the limits required by the gas turbine.

The plant installed cost estimate has been developed by utilising a combination of unit capacity factored and equipment factored estimating techniques and quotes from licensers/vendors. These methods utilize historical data from plants with similar units or equipment.

The costs for some units that are typically provided as a package are obtained from vendors or licensers of these units. Such units include the gasification unit, air separation unit, sulphur recovery unit and coal handling and storage unit.

The accuracy of the cost estimates is ± 35%. The currency exchange rates used were:

- $1.00 US = $1.15 CAN
- 1.00 € = $1.50 CAN
- 1.00 £ = $2.27 CAN

The base estimates developed on a USGC basis were adjusted to a local site basis and fourth quarter 2007 time frame using location specific information. Adjustments were made to USGC labour efficiency, labour rates, bulk materials, and indirect construction cost factors as detailed in the cost section of this report.

The CO_2 price uses the concept of “break-even” (BE) price instead of cost of capture or avoided cost. Also included for comparison purposes are both the cost of capture and avoided costs. The break even cost of CO_2 was determined by driving up the credit price until the first year cost of power for a reference coal plant without capture equals the first year cost of power for the carbon capture plant. When the price of CO_2 credits are below the BE price, one would build SCPC and buy CO_2 credits. When the price of CO_2 credits is above the BE price, one would build a plant with CO_2 capture. It was assumed that beginning in 2018, once a plant met the CCS CO_2 intensity requirements, no offset credits could be sold.

The first year cost of power was determined by finding the first year power price, escalating by 2% each year, which sets the NPV of the project equal to zero. By definition when the NPV of a project is zero, the NPV of the revenue equals the NPV for the costs. This price profile can be compared to a nominal power price forecast.

Table 4 Summary of Costs and Plant Performance						
Coal Type	**Lignite**			**Sub-bituminous**		
Case Number	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6
Case Description	Capture	Capture Ready	Non Capture	Capture	Capture Ready	Non Capture
Coal Feed (Wet) (t/h)	369	366	336	284	274	254
Net Plant Output (MW)	483	609	571	481	543	524
Plant Efficiency (%) (HHV)	31.5	40.0	40.9	32.6	38.1	39.6
Total Plant Cost ($ x 10^6)	$3,421	$3,142	$3,032	$2,626	$2,494	$2,276
Total Plant Cost ($/kW)	$7,083	$5,159	$5,310	$5,459	$4,593	$4,344
Total Capital Req'mt ($ x 10^6)	$4,841	$4,349	$4,194	$3,581	$3,297	$3,013
Total Capital Req'mt ($/kW)	$10,023	$7,141	$7,345	$7,445	$6,073	$5,751
First Year Cost of Power ($/MWh)	$224.1	$180.4	$184.5	$168.2	$156.1	$148.5
Break-Even Cost of CO_2 ($/t)	$188	--	--	$148	--	--
Capture Cost of CO_2 ($/t)	$159	--	--	$128	--	--
Avoided Cost of CO_2 ($/t)	$208	--	--	$153	--	--
CO_2 Capture Rate (%)	84			74		
CO_2 Emission Intensity (t/MWh)	0.18	0.88	0.86	0.27	0.90	0.87

Table 5 Power Summary						
Coal Type	**Lignite**			**Sub-bituminous**		
Case Number	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6
Case Description	Capture	Capture Ready	Non Capture	Capture	Capture Ready	Non Capture
Power (MW)						
Gas Turbine	431	408	431	422	409	419
Steam Turbine	258	292	266	198	215	191
Expander	14	22	11	0	0	0
Gross Power	703	722	708	620	624	610
Site Auxiliary Power	220	113	137	139	81	86
Net Power	**483**	**609**	**571**	**481**	**543**	**524**

Table 6	First Year Cost of Electricity ($ per MWh in 2013)					
Coal Type	**Lignite**			**Sub-bituminous**		
Case Number	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6
Case Description	Capture	Capture Ready	Non Capture	Capture	Capture Ready	Non Capture
CO_2 Commodity Sales	-12.8	--	--	-10.5	--	--
CO_2 EOR Offset Sales	-7.1			-5.9		
Sequestered Offset Sales	-7.1	--	--	-5.9	--	--
CO_2 Offset Cost	9.8	6.8	6.4	7.8	7.0	6.5
Coal Costs	17.2	13.6	13.3	13.9	11.9	11.4
Transmission	4.2	3.3	3.5	4.2	3.7	3.9
O&M and Other	47.7	34.0	35.0	36.6	29.2	27.9
Equity Return	86.8	61.8	63.6	64.5	52.6	49.8
Debt	61.5	43.8	45.1	45.7	37.3	35.3
Working Capital	0.4	0.3	0.3	0.5	0.4	0.4
Taxes	23.6	16.8	17.3	17.3	14.2	13.4
Total Cost	**224.1**	**180.4**	**184.5**	**168.2**	**156.1**	**148.5**

E) GASIFICATION TECHNOLOGY OPTIMIZATION – STAGE 2

In the previous Stage 1 of the project, a variety of gasification technologies and process configurations were evaluated by Jacobs for processing of either lignite coal or sub-bituminous coal to produce a syngas fuel suitable for powering a gas turbine.

The focus of the Stage 2 work is to improve the economics of the demonstration plant by taking advantage of some of the potential feedstock and product synergies of constructing the plant near a oil sands upgrading unit. For this purpose, two changes from the Stage 1 cases were identified for implementation in Stage 2. These were switching from 100% coal feedstock to 50% coal/50% petroleum coke, and configuring the plants to produce both power and hydrogen with one GE 7FB gas turbine operating in combined cycle with the remaining syngas being sent to a PSA unit to produce pure hydrogen product.

Four cases were selected for study in Stage 2; the same case numbers as used in Stage 1 for the equivalent cases have been used for ease of cross reference.

- Lignite Coal / Petroleum Coke
  - Case 1 - CO_2 Capture Case
  - Case 2 - CO_2 Capture Ready Case
- Sub-bituminous Coal / Petroleum Coke
  - Case 4 - CO_2 Capture Case
  - Case 5 - CO_2 Capture Ready Case

The non-capture cases considered in Stage 1 were not pursued in Stage 2; therefore the total number of cases was reduced from six to four.

Similar to Stage 1, the design objective for Stage 2 of the project as specified by CCPC is to configure the plants to have a high efficiency while maintaining cost effectiveness.

Design Basis

This design basis establishes the technical basis for performing Stage 2 of the Gasification Case Optimization Study in which the performance and capital and operating costs of four greenfield polygeneration plants are developed. These polygen plants were configured to gasify a blend of coal and petcoke to produce pure hydrogen and to feed one GE 7FB gas turbine operating in combined cycle. Two coals are studied, Alberta sub-bituminous and Saskatchewan lignite, each with and without CO_2 capture.

While the minimum availability target for the Stage 1 work was 85% operating on coal/coke alone, hydrogen is required at a much higher availability of 95%. This requires sparing of certain elements of the plant, including the gasifier, and this sparing also results in an increase in the availability of the power to 90%. Natural gas is not used as a backup fuel.

Otherwise, the design basis is similar to the Stage 1 portion of the study.

Process Descriptions

Coal and petcoke are delivered to the site by truck and are stored separately in covered storage building. Each feed from storage is separately fed via weigh feeders to regulate the flow, and is milled and either dried with a steam heated fluidized bed dryer or mixed into a slurry with water, depending on the gasifier to which it is being fed. The lignite coal is a low rank coal and would form a low solids content slurry. It is therefore used in the “dry feed” gasifier. The sub-bituminous coal has low inherent moisture and forms a slurry with a sufficiently high solids content. It is therefore fed to the “slurry feed” gasifier.

In all cases the mixed feed is gasified with a sub-stoichiometric amount of O_2 to produce a raw syngas stream consisting primarily of CO and H_2 with some CO_2. The O_2 feed to the gasifier is provided by an air separation unit. The sulphur in the feed is primarily converted to H_2S with a small amount of COS. The inorganic material in the feed is melted and cooled to form slag that is disposed of off site. The lignite cases have a blowdown water stream from the gasifier which is treated, and a portion is recycled to the gasifier vessel. The remaining water is sent to the waste water treatment plant which produces a stream suitable for feeding to a demineralised water plant and a stream to be sent to an evaporation pond. The sub-bituminous coal cases use a gasifier which does not have a blowdown water stream. Water from slag dewatering is recycled to the slurry preparation system.

The saturated raw syngas stream from the gasifier is passed through shift reactors where the CO in the stream reacts with the water vapour in the stream to produce H_2 and CO_2. Heat liberated in this section of the plant is used to raise steam to produce power in steam turbines. The ‘shifted’ syngas stream is then cooled and the water vapour is condensed and recycled to the gasifier. In the capture cases the H_2S and CO_2 in the syngas are then removed in a Selexol® absorption process. In the capture ready cases H_2S and a portion of the CO_2 is removed in the Selexol® plant (CO_2 is only removed from the syngas used for hydrogen production). Acid gas from the H_2S removal process is sent to a Claus sulphur plant to recover the elemental sulphur which can be sold. In the capture cases the CO_2 is compressed, dried and exported. In the capture ready cases the CO_2 is purified and vented.

Part of the syngas leaving the acid gas removal plant is then fed to the gas turbine. The remaining syngas is sent to the pressure swing adsorption (PSA) unit which separates the syngas to produce a pure hydrogen product stream. In the lignite cases the syngas for the gas turbine is first dropped in pressure from 75 bara to 30 bara in a turbo expander. In the sub-bituminous cases the syngas leaving the acid gas removal unit is at around 30 bara, and therefore there is no turbo expander. The syngas stream is mixed with offgas from the PSA unit then heated and fed as fuel to a GE 7FB gas turbine. Nitrogen is added to the gas turbine combustion chamber in order to suppress the flame temperature and reduce NOx formation. An SCR catalyst is fitted to the exhaust of the gas turbine in order to reduce the NOx concentration to the required level.

Performance and Cost Summary

The overall performance and cost figures for the four gasification options are summarized in Tables 7, 8 and 9 below.

For lignite coal, the feed flow rate required is slightly different for each case. This is because the syngas fuel required by the 7FB gas turbine varies depending on the syngas composition and this is different for both of the cases. For the sub-bituminous coal cases, the proportion of hydrogen produced is adjusted to keep the same feed rate to the gasifiers.

The plant installed cost estimate has been developed by utilising a combination of unit capacity factored and equipment factored estimating techniques and quotes from licensers/vendors. These methods utilize historical data from plants with similar units or equipment.

The costs for some units that are typically provided as a package are obtained from vendors or licensers of these units. Such units include the gasification unit, air separation unit, sulphur recovery unit and coal handling and storage unit.

The accuracy of the cost estimates is ± 35%. The currency exchange rates used were:

- $1.00 US = $1.15 CAN
- 1.00 € = $1.50 CAN
- 1.00 £ = $2.27 CAN

The base estimates developed on a USGC basis were adjusted to a local site basis and fourth quarter 2007 time frame using location specific information. Adjustments were made to USGC labour efficiency, labour rates, bulk materials, and indirect construction cost factors as detailed in the cost section of this report.

The CO_2 price uses the concept of "break-even" (BE) price instead of cost of capture or avoided cost. Also included for comparison purposes is the cost of capture. The avoided cost calculation is not meaningful in this instance since all the emissions are borne by the electricity portion. The break even cost of CO_2 was determined by driving up the credit price until the first year cost of power for a reference coal plant without capture equals the first year cost of power for the carbon capture plant. When the price of CO_2 credits are below the BE price, one would build SCPC and buy CO_2 credits. When the price of CO_2 credits is above the BE price, one would build a plant with CO_2 capture.

The first year cost of power was determined by finding the first year power price, escalating by 2% each year, which sets the NPV of the project equal to zero. By definition when the NPV of a project is zero, the NPV of the revenue equals the NPV for the costs. This price profile can be compared to a nominal power price forecast.

Table 7 Summary of Costs and Plant Performance				
Coal Type	**Lignite**		**Sub-bituminous**	
Case Number	Case 1	Case 2	Case 4	Case 5
Case Description	Capture	Capture Ready	Capture	Capture Ready
Coal Feed (Wet) (t/h)	138	141	124	123
Petcoke Feed (Wet) (t/h)	138	141	124	123
Net Plant Output (MW)	199	253	145	199
Hydrogen (Nm^3/h)	245,400	256,900	222,700	224,200
Plant Efficiency (%) (Note 1)	58.5	62.2	52.8	56.5
Total Plant Cost ($ x 10^6)	$3,651	$3,600	$3,102	$3,036
Total Capital Req'mt ($ x 10^6)	$5,454	$5,276	$4,470	$4,283
First Year Cost of Power ($/MWh)	$358.6	$326.0	$348.3	$311.4
Break-Even Cost of CO_2 ($/t)	$101	--	$85	--
Capture Cost of CO_2 ($/t)	$105	--	$79	--
CO_2 Capture Rate (%)	74.1		79.8	

Note 1: HHV efficiency, based on net power output and HHV of H_2 product

Table 8 Power Summary				
Coal Type	**Lignite**		**Sub-bituminous**	
Case Number	Case 1	Case 2	Case 4	Case 5
Case Description	Capture	Capture Ready	Capture	Capture Ready
Power (MW)				
Gas Turbine	213	199	207	196
Steam Turbine	199	203	118	123
Expander	3	7	0	0
Gross Power	414	409	325	319
Site Auxiliary Power	215	155	181	120
Net Power	**199**	**253**	**145**	**199**

Table 9	First Year Cost of Electricity ($ per MWh in 2013)			
Coal Type	**Lignite**		**Sub-bituminous**	
Case Number	Case 1	Case 2	Case 4	Case 5
Case Description	Capture	Capture Ready	Capture	Capture Ready
CO_2 Commodity Sales	-33.9	--	-44.9	--
CO_2 EOR Offset Sales	-18.8	--	-24.9	--
Sequestered Offset Value	-18.8	--	-24.9	--
Hydrogen Sales	-176.2	-145.1	-219.6	-161.0
CO_2 Offset Cost	7.0	7.0	7.0	7.0
Coal & Petcoke Costs	40.1	32.3	30.4	22.0
Transmission	1.9	1.5	2.6	1.9
O&M and Other	114.5	94.0	123.9	94.1
Equity Return	225.3	171.4	253.4	176.9
Debt	174.0	132.4	195.7	136.6
Working Capital	1.8	1.0	2.6	1.3
Taxes	41.7	31.5	47.1	32.5
Total Cost	**358.6**	**326.0**	**348.3**	**311.4**

F) DISCUSSION OF RESULTS FOR GASIFICATION TECHNOLOGY OPTIMIZATION – STAGES 1 & 2

Table 4 shows that the plant costs in $/kW for a plant using a gasification technology operating on sub-bituminous coal are lower than for a plant using a gasifier operating on lignite coal. The $/kW values for the sub-bituminous cases are between 77% and 99% of the $/kW values for the lignite cases, depending on whether a CO_2 capture, capture ready or non-capture plant is being used. The sub-bituminous cases are cheaper than the lignite cases in all plant areas including the high cost areas of air separation, gasification and power production.

The air separation unit is less expensive for the sub-bituminous coal cases because the O_2 requirement is less for the sub-bituminous gasifier. In this gasifier only the recycled char is fully gasified and not the entire feed stream.

The gasification unit is cheaper for sub-bituminous cases for the following reasons:

- The sub-bituminous gasification unit has fewer equipment items than the lignite process. There is a much smaller blowdown water treatment requirement in the sub-bituminous gasifier, as there is no quench system. All the water from the sub-bituminous gasifier blowdown is recycled back to the slurry preparation area.
- The sub-bituminous gasifier is refractory lined and does not contain the more expensive membrane cooling screen arrangement that the lignite gasifier uses.
- The lignite gasifier operates at 80 barg which is nearly twice the operating pressure of the sub-bituminous gasifier which operates at around 45 barg. The higher operating pressure may lead to more expensive pressure vessels, etc. However, higher pressure operation

does reduce the overall cost of the plant due to the lower volumetric flowrates of syngas that are handled.

The power block cost is cheaper for the sub-bituminous cases due to the combined cycle power plant being smaller. In the sub-bituminous cases, much of the steam produced in the combined cycle is used in the process as opposed to making power in the steam turbines. This means that the steam turbines are smaller and the power block is cheaper.

The lignite coal cases have higher efficiencies than the sub-bituminous cases for the capture ready and non-capture cases, in spite of the lower quality of the lignite coal compared to the sub-bituminous coal. This is attributable to the improved heat recovery that can be achieved with the lignite cases as they operate at significantly higher pressure than the sub-bituminous cases. The lignite gasifier also has heat recovery in the tubes in its walls. The overall plant efficiency for the capture cases is lower for the lignite coal than the sub-bituminous coals. This is due to the high CO_2 production from the lignite coal.

For a given coal, the capture cases have the lowest efficiency, as they have the large power requirement of the CO_2 removal and export system. The non-capture cases have a higher efficiency than the capture ready cases. In the capture ready cases the shift reaction converts the chemical energy in the syngas into heat liberated in the exothermic reaction. The heat liberated is used to generate HP steam which can be used to produce power at around 25% efficiency in steam turbines in the combined cycle. In the non-capture cases there is no shift reaction and the chemical energy in the syngas stays with the syngas all the way to the gas turbine where it can be used to make power at over 65% efficiency in the gas turbine combined cycle.

Conclusions

These two stages of the gasification optimization study have taken two gasification technologies, each operating on a different feedstock, and developed preliminary performance data and engineering deliverables along with a +/-35% cost estimate. It should be noted that both of the gasification technologies were considered to be “next generation” technologies, i.e. they would not be available commercially for at least a decade or more.

The sub-bituminous gasification technology is found to be significantly cheaper than the lignite cases with the plant installed cost being typically only 76% to 88% of the cost. This saving is due to a combination of improved gasifier efficiency (82% for sub-bituminous gasifier, 79% for lignite) and a higher grade coal (sub-bituminous with 20% moisture for sub-bituminous cases, lignite with 33% moisture for lignite cases).

The lignite coal cases have higher efficiencies than the sub-bituminous cases, in spite of the lower quality of the lignite coal compared to the sub-bituminous coal. This is attributable to the improved heat recovery that can be achieved with the lignite cases as the lignite gasifiers operate at significantly higher pressure than the sub-bituminous cases. The lignite gasifier also has heat recovery in the tubes in its walls

It can be seen that for each feedstock, the capture case has a lower efficiency than the capture ready case, as the capture cases have the large power requirement associated with the CO_2 export system and nitrogen diluent addition.

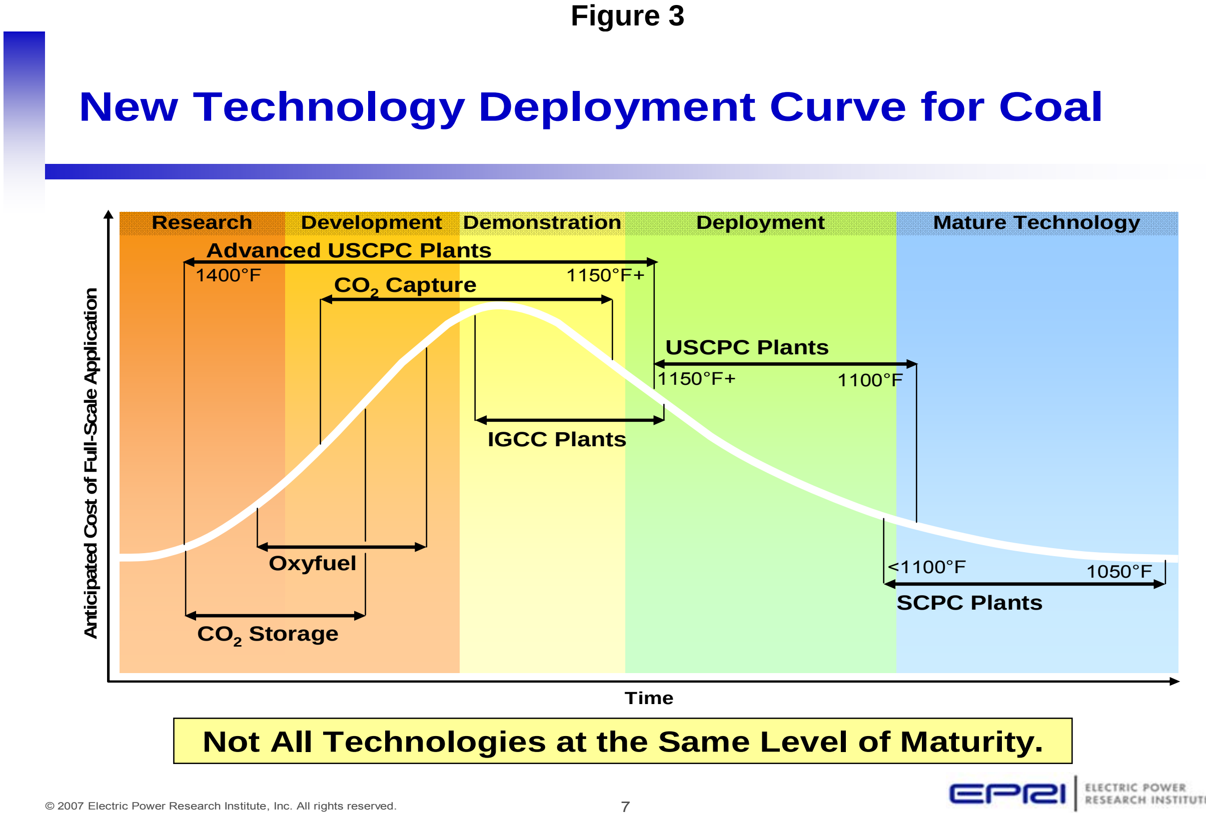
The capital cost of the capture ready cases is only marginally less than that of the equivalent capture case. Later conversion of a capture ready plant to capture operation will result in a higher overall capital cost. In addition, the net revenue from a capture ready plant is significantly less than that of a capture plant, overshadowing the lower capital cost of the capture ready plant. It is therefore considered to be judicious to construct a capture plant from the outset, rather than a capture ready plant for later modification. While a non-capture plant would have a lower initial capital cost, conversion of a non-capture plant to capture operation would require major plant modifications, and result in a much higher overall cost than that of a converted capture-ready plant or a purpose built capture plant.

G) PHASE II CONCLUSIONS & RECOMMENDATIONS

The use of technical economic evaluations is a vitally essential and necessary continuing activity throughout the research, development and demonstration of any potential commercial technology. However there are many challenges that arise during such evaluations particularly with technologies at an early stage of development where the error band or range (% & ±) that should be attributed to the capital and operating cost estimates is inevitably broad. As part of such evaluations it is usual to include comparisons with other competing technologies which may be at different stages of development, some near commercial and some still only conceptual.

There is a well established common trajectory and experience curve for technical developments as illustrated in Figure 3 for coal based technologies for power generation.

Figure 3



The usual path is that a promising idea is conceived and the early evaluations focus on the potential advantage and tend to show optimistic cost and performance estimates. As the technology develops through experimentation at bench and pilot scale new insights of a more practical and detailed nature become evident that lead to higher cost estimates. The highest projected cost per unit of product or output occurs at the near commercial demonstration stage where the actual capital investment and associated economic risks are at their highest. Assuming a successful demonstration at near commercial scale that confirms the major benefits of the technology, the usual path is for successive plants to show steady incremental improvements in performance and the economics of scale as a result of the learning accumulated with experience over time.

In Phase 2 of the CCPC work further studies were completed on the three major concepts for CO_2 capture from coal based plants – namely IGCC pre-combustion, PC post combustion and oxyfuel combustion. In general these three approaches to capture are at different stages of development. The gasification shift and CO_2 removal aspects for pre-combustion capture in IGCC are commercially available at the commercial scale however the performance of a modern large gas turbine operating on hydrogen gas has yet to be demonstrated. The post combustion capture from PC flue gas using the state of the art MEA solvent has to date only been used at the scale 15 MWe equivalent and other possibly more efficient solvents are at an even earlier stage of development. Oxyfuel combustion is at the beginning of its development with the first pilot plants at ~10 MWe equivalent (30 MWth) just starting their test programs. So there are risks associated with each of the technologies with the nature of the risks differing in type and scale among the technologies.

Although not studied here, CO_2 storage via enhanced oil recovery is well established but saline reservoir storage is not and must be regarded as somewhere lower on the ascent curve.

When reviewing the results of the Phase 2 studies it is important to understand the actual development status of each of the specific technologies studied.

Gasification

Although the pre-combustion capture of CO_2 from syngas is commercially well established the gasification technologies selected in these Phase 2 studies were considerable less developed than the commercial GE and Shell technologies studied in the earlier Phase 1. However at the time these technologies were selected they appeared to offer the potential of improved cost and performance with low rank coals. The sub-bituminous technology is just a concept with no experimental data and subsequent to its selection for the study in 2006 the licensor has now decided not to proceed with its development. It was conceived as a technology with higher gasification efficiency and lower oxygen consumption however its alleged advantages became diminished during the course of the study in the context of CO_2 capture. So the results from this IGCC case study on the sub-bituminous coal cannot be regarded as consequential.

The gasification technology selected for the lignite IGCC in Phase 2 is also at a much earlier stage of development than the Shell technology used in Phase 1. It was operated at the 200MWth scale in the late 1980s and several 500 MWth size gasifiers have been supplied to China for planned 2009 start up. For the CCPC Phase 2 study 500 MWth gasifiers were selected, however these are still too small to provide the syngas needs for a 7 FB gas turbine so the number of gasifiers and their cost is high. Furthermore they were assumed to operate at a much higher pressure (78 Bar) than has been demonstrated. This doubles the requirement for nitrogen feed conveying gas. A previous study conducted for the IEA had concluded that for a dry coal fed gasifier there was no advantage to go to the higher pressure. The added costs of drying lignite to the moisture level necessary to ensure safe and reliable coal feeding to the gasifier are also significant.

Post Combustion Capture

The scope of supply and performance of an SCPC plant with FGD and SCR are well known and their cost estimate will have a more confident and lower band breadth than either IGCC or oxyfuel combustion technologies. The post combustion capture with MEA needs to be scaled up from its demonstrated 15 MWe size. However the type of equipment required has some similarities to FGD. Overall the cost and performance estimates for SCPC with post combustion capture using MEA are probably more confidently known than those for IGCC with pre-combustion capture and for oxyfuel combustion.

Oxyfuel Combustion

Since the first oxyfuel combustion pilot plants are only now undertaking their first tests the error band for the cost and performance estimates on this technology will be higher than for either SCPC with post combustion capture or IGCC with pre-combustion capture. The flue gas clean up requirements for either recycle or for sequestration have yet to be established with confidence and advanced technology for CO_2 purification has not been demonstrated.

Concluding Comments on the Phase 2 Cases

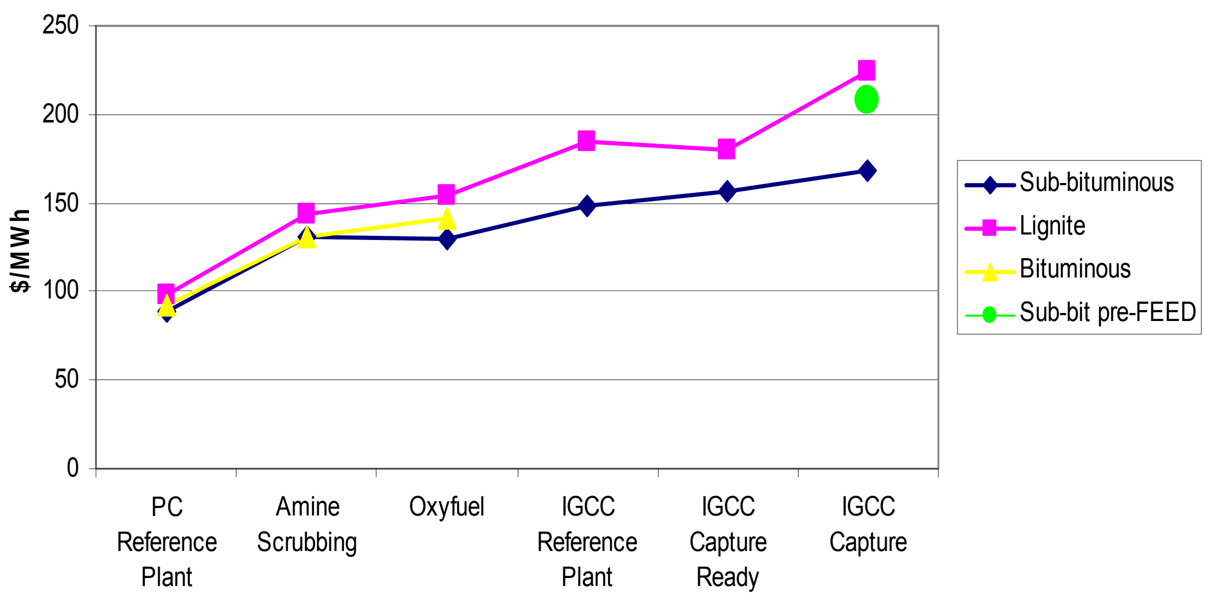
1. SCPC + amine scrubbing cost estimates have the smallest error band.
2. Oxyfuel combustion cost estimates have the largest error band. More experimental results are required to enable a significant comparison with post combustion capture
3. There are considerable development activities aimed at improved solvents for post combustion capture (e.g. chilled ammonia). Since both post combustion capture and oxyfuel combustion are both subjects of considerable development activity the economic comparison will doubtless continue to exhibit considerable uncertainty for many years to come.
4. The gasification technology used for the sub-bituminous IGCC is conjectural and is not being developed so no significant conclusion can be made from this case regarding the use of IGCC for the sub bituminous coal.
5. At this stage in its development the gasification technology used for the IGCC lignite case does not appear likely to be competitive with SCPC post combustion capture. Additional improvements in gasifier size and in less energy intensive and expensive coal drying are needed.

Keeping the above comments in mind, the overall economics, as measured by the cost of electricity (COE), are shown in Figure 4. As expected, the pulverized coal (PC) reference plant with no CO_2 capture provides the lowest COE. This graph also indicates that amine scrubbing and oxyfuel combustion technologies on PC plants are essentially equal, depending on the specific site conditions. This graph also confirms that IGCC is a technology that is very dependent on the fuel quality. The COE for lignite coal is higher than for sub-bituminous coals.

The polygeneration cases, shown in Tables 7, 8 and 9, are not shown on these graphs as the process configuration has not been optimized yet. In this case, the COE depends on the value assigned to the sale of hydrogen. A low hydrogen price will mean a high COE price, and vice versa. The hydrogen price assumed in this case was based on hydrogen from an SMR unit with natural gas about $8/GJ. If the cost of natural gas rises to $20/GJ, the COE for the polygeneration case with CO_2 capture (on sub-bituminous coal) goes from $322/MWh to $100/MWh. In this configuration, the price of natural gas will need to be high to allow the production of hydrogen from gasification to be competitive.

Figure 4

CCPC Phase II COE Comparisons



The capital costs are shown in Figures 5 and 6. Figure 5 shows $/kW on a net basis and Figure 6 shows the capital cost in billions of dollars. These are Total Plant Cost (TPC) values which are based on overnight construction and do not include escalation, owner's costs and interest during construction.

On a $/kW basis (Figure 5), the IGCC reference plant for sub-bituminous is less expensive than PC plants with CO_2 capture. For sub-bituminous coals, IGCC with CO_2 capture is only slightly more costly than amine scrubbing or oxyfuel.

From Figure 6, one can see the impact on fuel quality on IGCC technology. As expected, the lignite cases are more costly than the sub-bituminous cases.

The break-even (BE) cost of CO_2 is shown in Figure 7. This number indicates how costly CO_2 credits or offsets would need to be before one would make a decision to install CO_2 capture technology. These BE costs are currently much higher than the current values on the CO_2 markets.

Figure 5

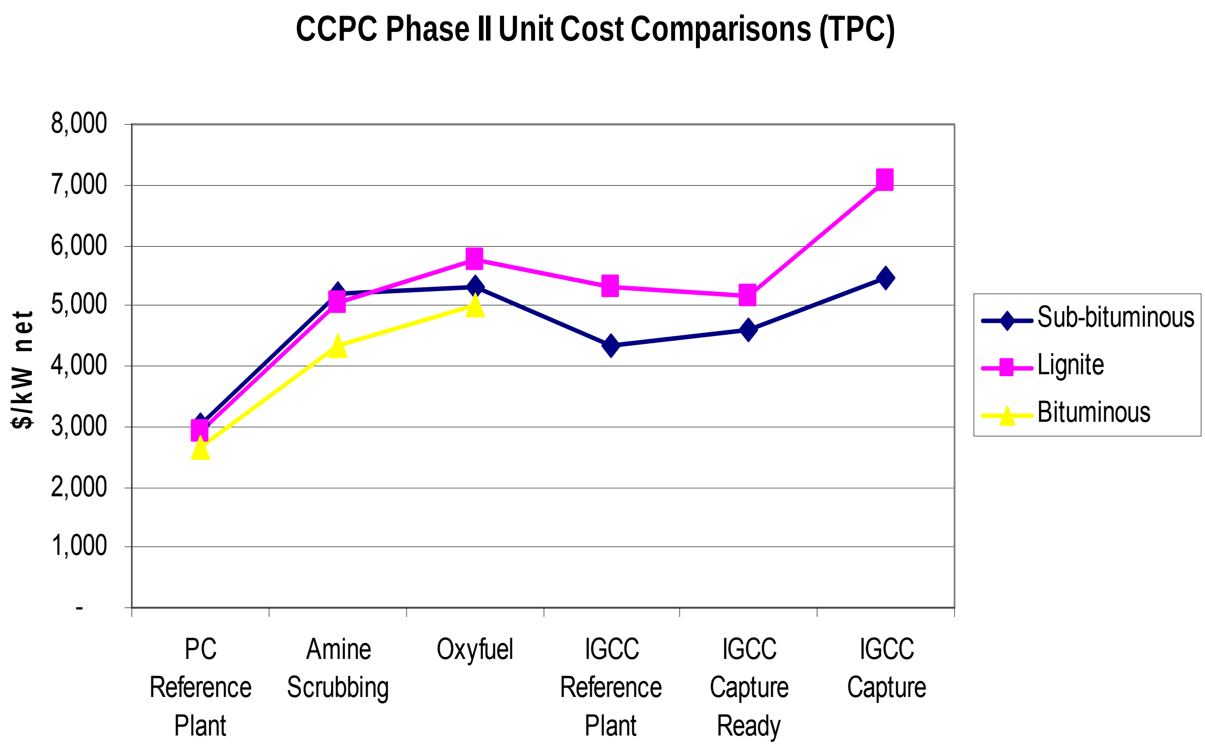


Figure 6

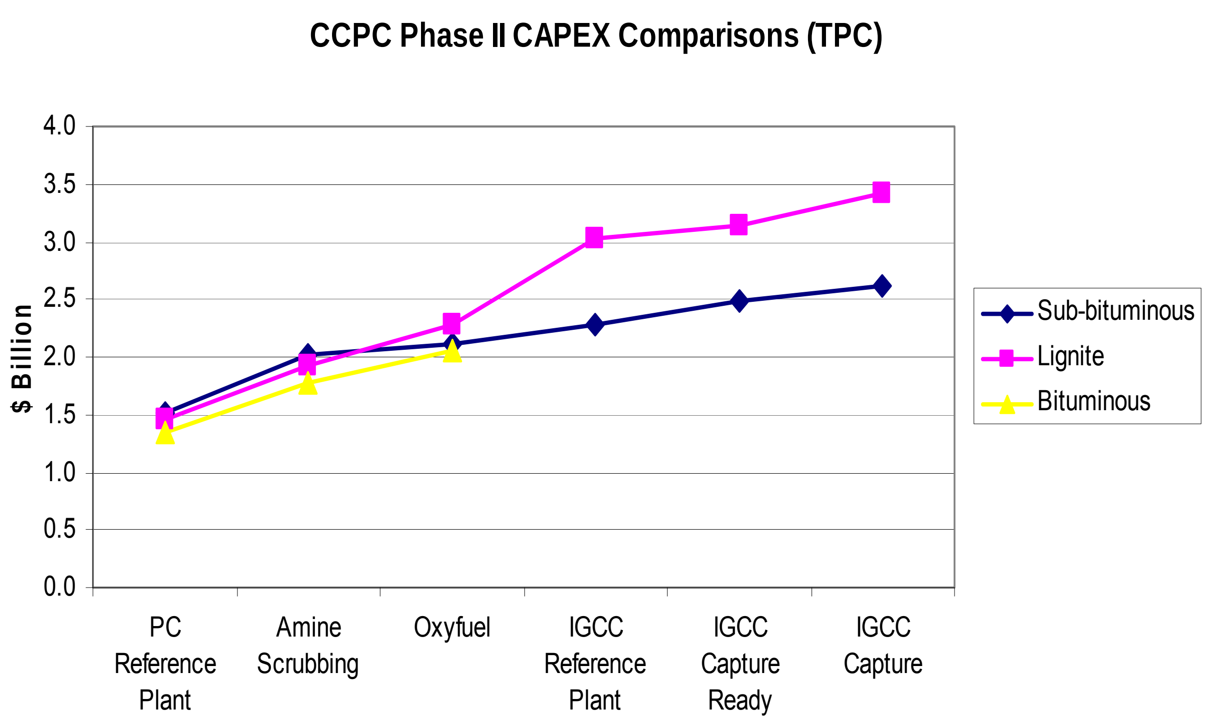
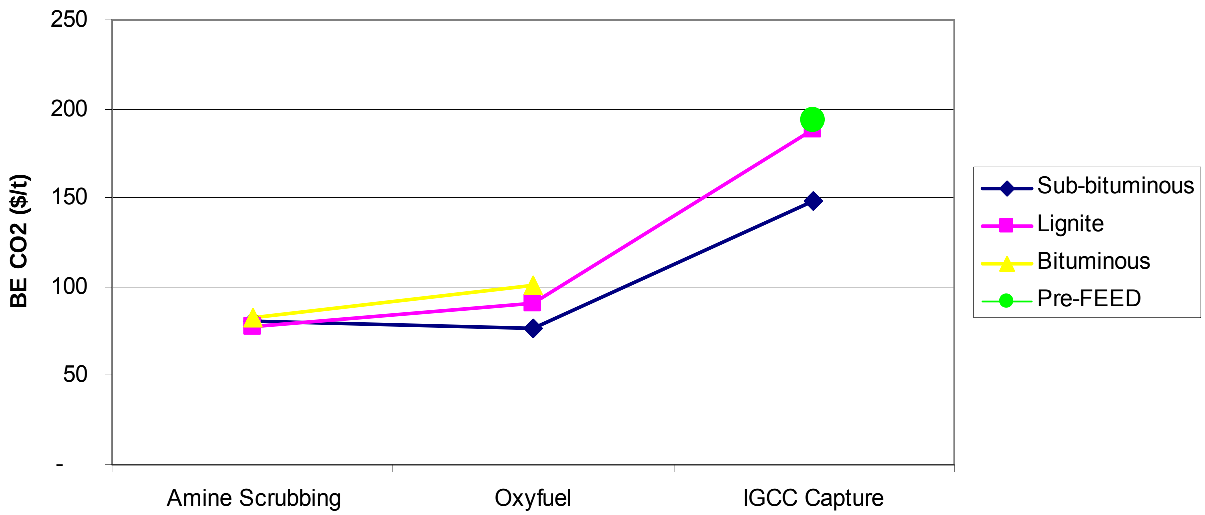


Figure 7

CCPC Phase II CO2 Cost Comparisons



From Figures 8 and 9, it can be seen the amine scrubbing and oxyfuel technologies were capable of higher CO_2 capture rates than gasification technologies, especially in the sub-bituminous case. The main reason is that some methane is produced in the sub-bituminous gasifier and this carbon is not captured. Other reasons are the inability to convert the entire CO to CO_2 in the shift reactor and the need to leave some CO in the hydrogen stream to the gas turbine as these turbines cannot yet operate on 100% hydrogen.

Figure 8 - CO_2 Emissions from Sub-Bituminous Coal

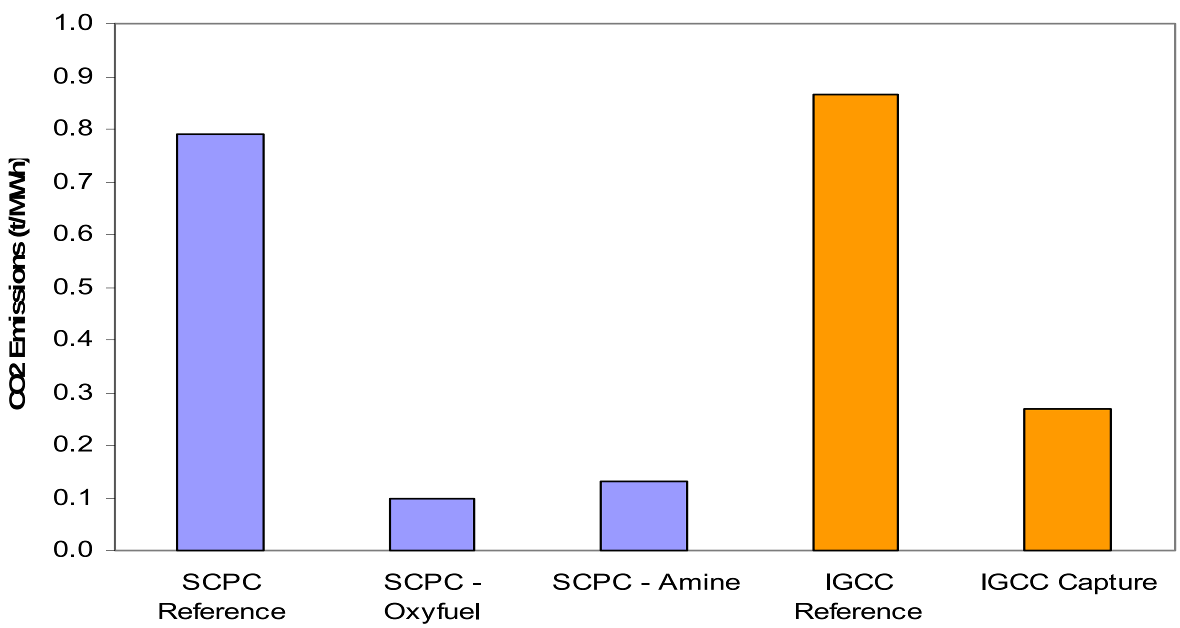
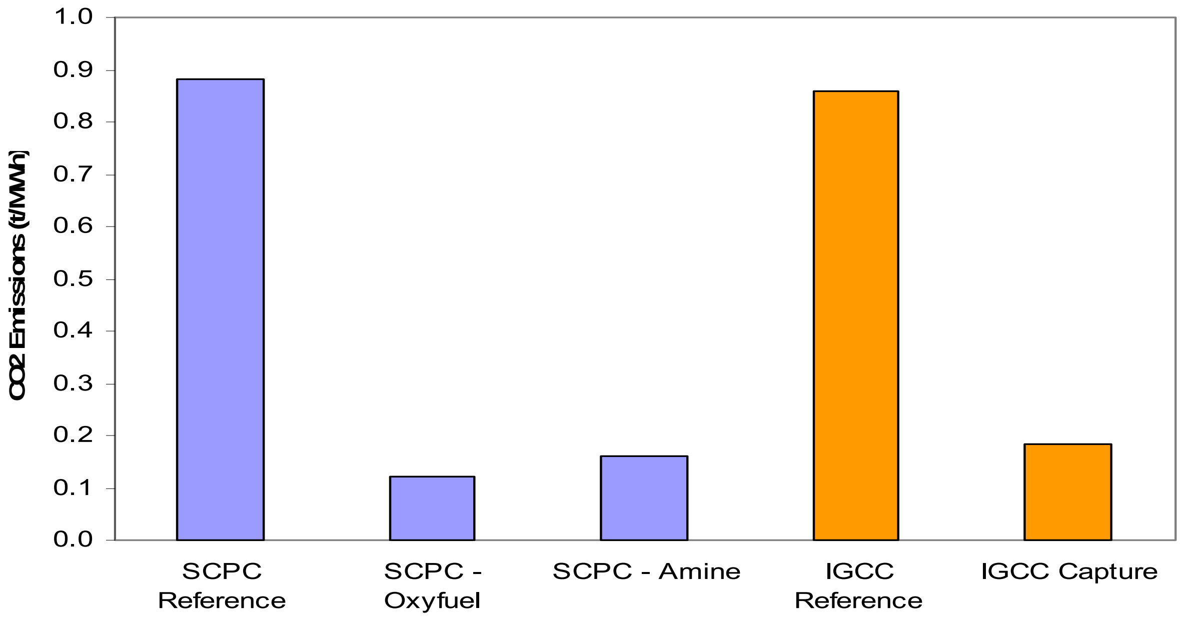


Figure 9 - CO_2 Emissions from Lignite Coal



Summary of Recommendations for Future Work

For carbon capture technology to make significant advances demonstration plants are needed to show the technology can work and to further optimize the processes based on actual plant operating data.

The key areas recommended for future work in each technology are summarized in Table 10.

Table 10	**Recommendations for Future Work**
All Capture Technologies	Defining, if possible, standardized purity requirements for captured CO_2, which would depend on the use or disposal point for the CO_2 (i.e. EOR, or sequestration) and the impact purity would have on capture costs. This can significantly affect costs. It is not known if there is one standard for EOR, CBM or sequestration which is applicable for all locations.
Oxyfuel & Amine Scrubbing – Balance of Plant	Integration of technologies into the power plant and between each sub-system (i.e. turbine is the main driver for amine, flue gas conditioning for oxyfuel). This may include determining the flexibility of boiler and turbine designs to accommodate better integration and efficiencies, while still providing the reliability and performance expected from a power plant.
Oxyfuel & Amine Scrubbing – Balance of Plant	Review of auxiliary power requirements (associated with integration). There is a major power penalty whichever CO_2 capture system is utilized and more design review is required to more accurately identify penalties, while optimizing overall plant integration.
Oxyfuel & Amine Scrubbing – Balance of Plant	Real site layout considerations, used to facilitate more accurate capital costing.

Amine Scrubbing – Steam Turbine Island	The 60Hz market power requirements has stretched the steam turbine aero-mechanical technology to the point where LP turbine efficiency has been compromised for cases where condenser pressure is low due to low ambient cooling water temperatures. Turbine expansion is increased within a flow-path flow area, constrained by blade mechanics, resulting in performance loss due to excessive flow Mach number.
Oxyfuel – Boiler Island	Demonstration of oxyfuel burner/combustion at full scale
Oxyfuel – ASU & CO_2 Compression	There is a need for a demonstration of the oxyfuel CO_2 capture purification and compression stages of the oxyfuel technology, from the direct contact cooler to the compressed, purified CO_2 product. Although based on known technology, demonstration at about 1 MWt scale is recommended to allow the expected performance to be validated. Such a 1MWt pilot plant would also allow quantification of unknowns, such as the fate of impurities in the raw flue gas.
Oxyfuel – ASU & CO_2 Compression	There is much to be gained from looking at optimization of the CO_2 compression system. In this study, Air Products has used adiabatic compression extensively with heat being recovered to the steam cycle. This may not be the best overall solution, especially in cases where cooling water is restricted. There may also be ways to utilize the fact that above its critical pressure CO_2 can be pumped. This could be combined with compression to lower the overall power consumption.
Oxyfuel – ASU & CO_2 Compression	Air Products have been working to improve the power consumption of capture rate of the CO_2 purification system and have cycles that increase recovery of CO_2 to above 97% without increasing power consumption. Also, they have been working on cycles that could efficiently either be producing the CO_2 as a liquid product for tanker transportation, or could be combined with CO_2 pumping to reduce overall power consumption, as mentioned above.
Oxyfuel – ASU & CO_2 Compression	Air Products is developing their Ion Transport Membrane (ITM) technology. A study of the oxyfuel conversion of boilers and heaters on a refinery site using an ITM Oxygen system to produce the oxygen showed that, when integrated into the current steam system, the ITM Oxygen system resulted in a cost of CO_2 capture around half that of the traditional cryogenic ASU.
Amine Scrubbing	This technology has been proven at a small scale, but significant scale-up is required to handle the gas flows from a full size power plant. A large slip-stream demonstration is required to validate the technology at larger scales.
Amine Scrubbing	Large-scale, long-term solvent testing on real coal flue gases might be an area of common interest, but difficulties arise due to the need accurately to assess coal and plant specific effects on flue gas composition and hence solvent chemistry changes in the long term.
Amine Scrubbing	Effective integration of amine systems with power plants is becoming reasonably well understood for base load conditions. Considerations for post-combustion capture to lend itself to flexible operation in order to follow electric system load requirements. Some areas that need to be addressed are amine plant performance mapping over a wide range of

	operating conditions and amine behaviour during storage.
IGCC	IGCC is commercially available today, but not with CO_2 capture. CO_2 capture needs to be demonstrated on a single train at full scale to prove out the designs.
IGCC	IGCC is commercially available today, but only for higher rank fuels such as bituminous coals and petcoke. Technology enhancements are required to make IGCC technology more economical for lower rank coals like sub-bituminous and lignite.
IGCC	FEED studies are required to improve the reliability of the cost estimates. This work is currently underway with the EPCOR/CCPC FEED study.
Polygeneration	Different process configurations need to be assessed to determine the most optimum approach to balance the needs of producing hydrogen and electricity.