Summary of Canadian Clean Power Coalition work on CO_2 capture and storage

by

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August 2004

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1 Introduction

The IEA Clean Coal Centre (IEA CCC) has participated in a series of studies on capture and storage of CO_2 organised by the Canadian Clean Power Coalition (CCPC). IEA CCC participated in the CCPC mainly as a cost-effective way of obtaining information on retrofit of CO_2 capture to power plants and the effects of coal rank on the costs of capture. This overview summarises the main results from the CCPC studies.

The CCPC was set up in mid 2001 by seven Canadian utility companies (ATCO Power, Emera Inc., EPCOR Utilities, Luscar, Ontario Power Generation, SaskPower and TransAlta Utilities). Subsequently IEA Environmental Projects Ltd, on behalf of IEA Greenhouse Gas R&D Programme and the IEA Clean Coal Centre, and EPRI joined the coalition, and the governments of Canada, Alberta and Saskatchewan agreed to provide financial support.

The goals of the CCPC are to:

- secure a future for coal-fired electricity generation within the context of Canada's multi-fuelled electricity industry.

- demonstrate that coal-fired electricity generation can effectively address all environmental issues projected in the future, including CO_2.

- research and develop commercially viable clean coal technology, and thence to construct and operate a full scale demonstration project to remove greenhouse gas and all other emissions of concern from an existing power plant by 2007, and a greenfield power plant by 2010.

Phase 1 of the CCPC consisted of conceptual engineering and feasibility studies to assess technologies and fuels that should be used in the demonstration plants and to identify options for storage of the CO_2 from a demonstration plant. Subsequent phases will consist of detailed design and construction of the plants. IEA CCC withdrew from the CCPC after Phase 1 because the costs of subsequent phases are beyond its financial resources.

The detailed reports of studies carried out in Phase 1 of the CCPC are confidential to members of the CCPC. This summary report contains only non-confidential information.

2 CCPC studies

The studies carried out in Phase 1 of the CCPC work are listed in Table 1.

Table 1 Studies carried out in Phase 1 of CCPC work

Subject	Contractor
Pre-screening study	SFA Pacific
Retrofit technologies for control of non-CO_2 emissions	Neil and Gunter
Amine scrubbing and oxyfuel combustion	Fluor
Gasification	Fluor
CO_2 storage and utilisation in Western Canada	SNC Lavalin
CO_2 storage in coal beds in Nova Scotia	Geological Survey of Canada

The pre-screening study recommended gasification for new greenfield power plants. Gasification may also be preferred for CO_2 capture at existing plants but most of the existing equipment would need to be discarded. Amine scrubbing and oxyfuel combustion would enable more of the existing equipment to be retained, which may appeal to some utilities. Based on these conclusions, the CCPC originally intended to evaluate amine scrubbing and oxyfuel technologies mainly for retrofits and to evaluate gasification mainly for greenfield plants. However, during the course of Fluor's studies it became apparent that retrofits would be less attractive than expected. The later stages of the studies therefore concentrated on greenfield applications for all technologies.

2.1 Plant sites and coal analyses

The CCPC study was based on three Canadian power plant sites, each using a different local coal:

- Trenton 6, a 156 MW plant in Nova Scotia, using bituminous coal
- Shand, a 272 MW plant in Saskatchewan, using lignite
- Genessee 1, a 391 MW plant in Alberta, using subbituminous coal

Analyses and costs of these coals are given in Table 2. The energy content per kg C decreases with decreasing coal rank, and hence the specific emissions of CO_2 increase.

Table 2 Coal analyses and costs

	Nova Scotia Bituminous	Alberta Subbituminous	Saskatchewan Lignite
Moisture, wt% as-received	5.89	20.00	33.54
Ash, wt% as-received	7.95	13.93	13.46
Carbon, wt% dry-ash free	84.66	73.93	74.67
Hydrogen, wt% dry-ash free	5.99	4.26	4.85
Oxygen, wt% dry-ash free	5.07	20.51	18.30
Nitrogen, wt% dry-ash free	1.54	0.91	1.26
Sulphur, wt% dry-ash free	2.74	0.39	0.92
LHV, MJ/kg as-received	28.95	17.81	13.56
Specific energy content, MJ/kg C	39.68	36.46	34.26
Cost, US$/GJ (LHV)	1.90	0.48	0.88

2.2 Economic basis

The economic analyses in the CCPC study were based on assumptions such as rates of return on capital and taxation rates that are appropriate for power plants in Canada. The economic analyses were done using an EPRI model.

The economics in the CCPC's reports are presented in Canadian dollars. For this IEA CCC overview they have been converted to US dollars using an exchange rate of 1.56 Canadian dollars per US dollar. This is the exchange rate that was used by the contractors to convert equipment costs in US dollars to Canadian dollars at the time the study was carried out.

The CCPC plants are designed for specific Canadian power plant sites. There are many location specific factors which can affect costs. Costs cannot be precisely converted to other locations.

3 Technologies for control of non-CO_2 emissions

This study identified foreseeable new regulatory requirements for emissions of substances other than CO_2 in Canada and assessed the costs of technologies to achieve these requirements. A wide range of technologies for SO_x, NO_x, particulate and mercury emission control were assessed. When CO_2 is captured, most other atmospheric emissions are also inevitably avoided, so the study provided a suitable baseline for assessment of the true incremental cost of CO_2 capture. Emission control targets were to be equal to, or better than, a natural gas fired combined cycle (NGCC) plant. The specific emission targets are identified in Table 3.

Table 3: Current and target emissions levels

Parameter	**Units**	**Coal Plants**						**NGCC**
Fuel		Lignite		Subbituminous		Bituminous		Natural Gas
Boiler Type		Wall Fired		Tangential		Wall Fired		HRSG
Primary		**Target**	**Current**	**Target**	**Current**	**Target**	**Current**	
NOx,	g/MWhr (ng/J)	50 (4.5)	- (258)	50 (4)	- (219)	50 (5)	- (258)	28 (5)
SOx	g/MWhr ng/J	55 (5)	- (602)	55 (5)	- (198)	55 (4.5)	- (1462)	4.5 (0.7)
Particulates PM10, PM2.5	g/MWhr ng/J	28 (2.5)	- (30.1)	28 (2.4)	- (15.1)	28 (2.8)	- (25.8)	15 (2)
Mercury	mg/MWhr pg/J	5.5 (0.5)	- (14)	3.5 (0.3)	- (10)	3.0 (0.3)	- (9)	N/A
CO	ppmv	40		40		40		45
SO3	ppmv	5		5		5		N/A
NH3	ppmv	1		1		1		1
Chloride	mg/Nm^3	5		5		5		N/A
Secondary Targets								
VOC	mg/Nm^3	1		1		1		1
Heavy Metals:								
Selenium	mg/Nm^3	6		6		6		
Arsenic	mg/Nm^3	6		6		6		
Cadmium	mg/Nm^3	2		2		2		
Note: 1) Units based on 3% O2 in flue gas. 2) NOX values expressed as NO2 3) SOX, NOX, $_{PM2.5,}$ Hg based on a 720 hr rolling average.								

NOTE: LONOX burners includes neural networks and OFA

Neill & Gunter identified and evaluated over 50 various control options that are either commercially available, or currently under development for SOx, NOx, fine particulate and mercury. In addition to this, over 25 emerging multi-pollutant approaches for managing emissions in innovative and cost effective ways were also identified.
To identify the most appropriate emission control technologies, a systematic or “Decision Analysis” procedure was followed which evaluated the technologies against a list of criteria including:

- removal efficiencies.
- commercial availability.
- favourable economics.
- feasibility of retrofit and commercial development of technology.
- risk associated with the installation on the overall system.

Each technology was then scored on its relative performance resulting in a comparative picture of the technologies. The technologies with the highest scores were selected for analysis relative to the reference plants. From the more than 75 technologies that were investigated at the outset, a total of 12 preferred technologies remained at the end of the Decision Analysis process.

Neill & Gunter developed multi pollutant control options and associated retrofit costs (capital and operating and maintenance) for *each* reference plant, including identification of system performance, synergistic effects, life cycle issues, risk and identification of any adverse consequences of implementing a particular system. The costs are presented in Table 4 and are based on manufacturers’ information, Neill & Gunter’s in house database, EPRI Technical assessment guide and USEPA program Coal Utility Environmental Cost (CUE COST).

Table 4: Technologies and costs to meet target emissions levels

Fuel	**Bituminous**			**Subbituminous**		**Lignite**	
Technology	**Option 1**	**Option 2**	**Option 3**	**Option 1**	**Option 2**	**Option 1**	**Option 2**
	LONOX burners SCR Wet scrubber AquaNOX scrubber	LONOX burners SCR LOTOX Airborne FGD Wet stack	Toxecon AquaNOX	LONOX Burners SCR Marsulex Activated Coke COHPAC	LOTOX Airborne FGD Wet stack	LONOX Burners SCR Marsulex Activated Coke COHPAC	LOTOX Airborne FGD Wet stack
Capital Cost ($millions)	283.6	365.2	234.8	237.1	274.6	301.7	258.8
Unit Size	165 gross			410 gross		298 gross	
Unit Cost ($/kW net)	909	1,171	753	717	721	1,110	952
O&M ($/MWhr)	6.73	6.57	5.53	9.49	4.19	11.24	6.52

The Neill & Gunter study confirmed the belief that meeting all emissions requirements, not including any requirements to limit CO_2 emissions, would require significant capital and have a major impact on the operating and maintenance costs of the plants. This fact could have a substantial influence on any decisions to capture CO_2 emissions.

4 CO_2 capture retrofit

Coal fired power plants are seriously at risk in a carbon constrained world since they emit large quantities of CO_2, larger than any other energy source. In addition, the CO_2 emitted is relatively impure, being diluted with large amounts of nitrogen, oxygen that has not been consumed in the combustion process, water vapour that is both a product of combustion and is entrained in the coal, as well as a multitude of other "pollutants" such as SO_X, NO_X, particulates, etc. In addition, the opportunities to store CO_2 generally require that the gas be relatively pure. The challenge, therefore, is to obtain a relatively pure stream of CO_2, with which it is feasible to do something. Three processes were investigated in the CCPC study: amine scrubbing, oxyfuel combustion, and gasification.

4.1 Amine scrubbing

Amine scrubbing is a process in which the flue gases from a conventional coal-fired boiler are passed through a large vessel (an absorber tower) and mixed intimately with a chemical solution containing an amine which selectively captures (absorbs) the CO_2. The amine with the CO_2 is pumped to another vessel (CO_2 stripper) in which the amine is processed (with large amounts of low quality heat) to release the CO_2, thereby producing a pure stream of CO_2 for disposal and storage. The cleaned or stripped amine is returned to the absorber tower to capture more CO_2, (see Figure 1).

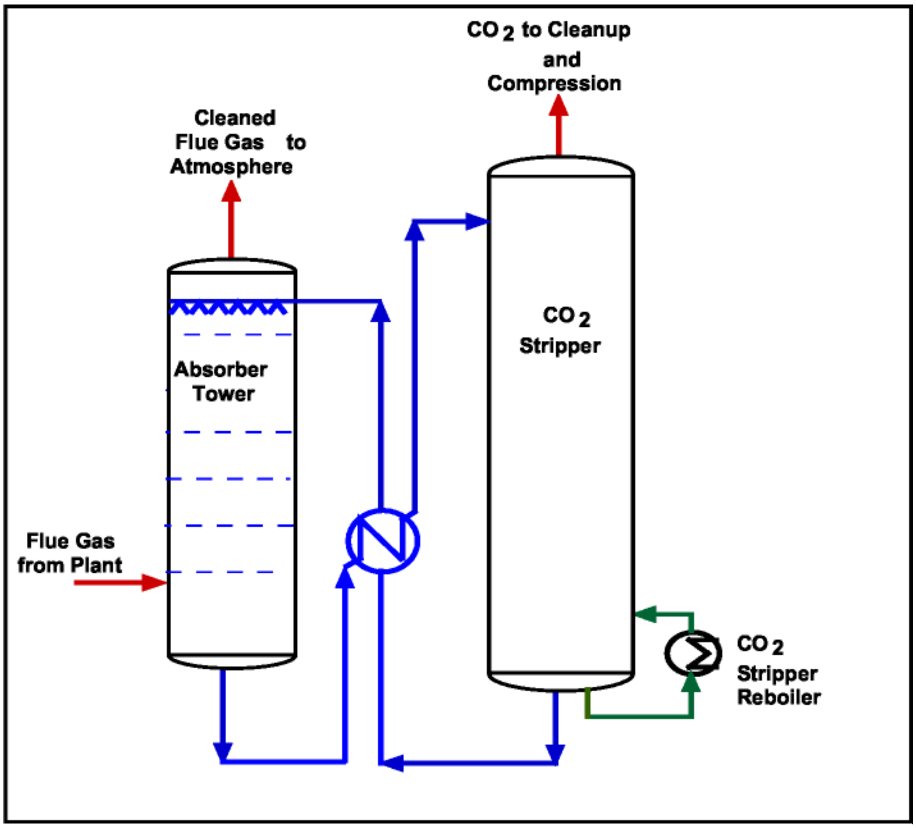

Figure 1 Amine scrubbing

4.2 Oxyfuel combustion

Oxyfuel combustion is a process in which coal is burned in an atmosphere of carbon dioxide (CO_2) and oxygen (O_2), rather than in a conventional atmosphere of air which is comprised largely of nitrogen (N_2) and oxygen (O_2), (see Figure 2). Thus the process replaces N_2 with CO_2, and is possible because only oxygen is active in the combustion process. The CO_2 is obtained from the boiler outlet and is recirculated to the boiler inlet. It is enriched with oxygen from an air separation plant to a level that is suitable for stable combustion. The process provides a relatively pure stream of CO_2, which is cleaned of other contaminants and purified for sale or storage. Natural Resources Canada has been working with the concept for many years, and has developed a pilot plant. The technology has never been operated at full scale.

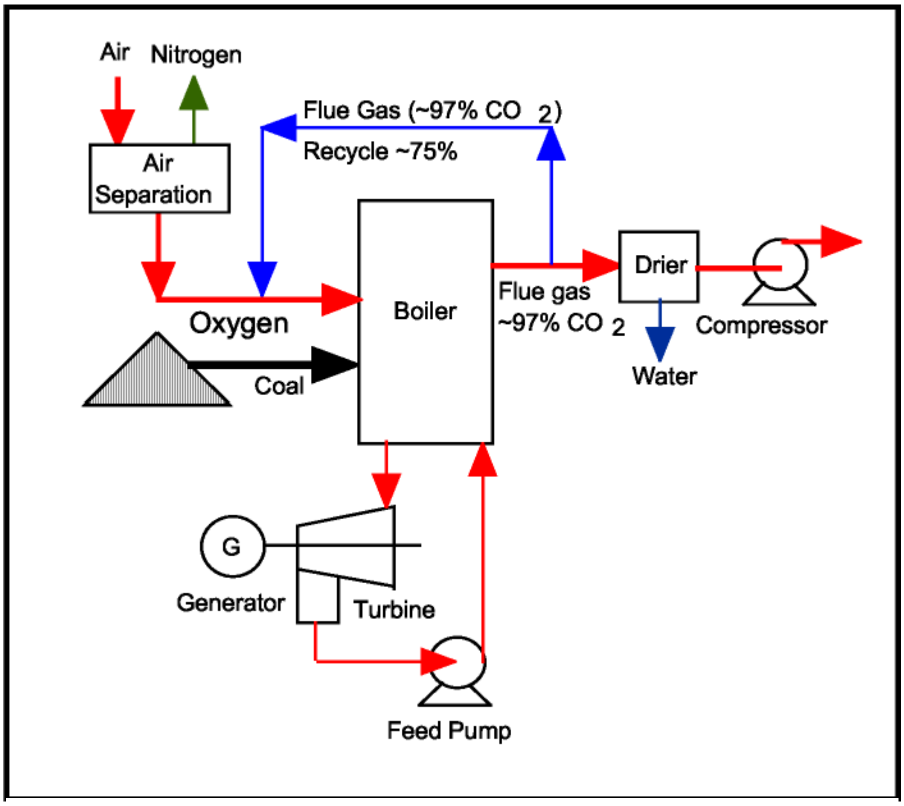

Figure 2 Oxyfuel combustion

4.3 Gasification

Coal gasification is the process by which the carbon in coal, in the presence of water and air, is converted directly to carbon monoxide (CO), carbon dioxide (CO_2), and hydrogen (H_2), (see Figure 3). Thus, the process provides a relatively pure stream of CO_2 for disposal. Coal gasification has been used for more than a hundred years and is a technology that is well known by the chemical and petrochemical industries. The gasification process is marketed today by several technology licensors each of whom have different proprietary processes.

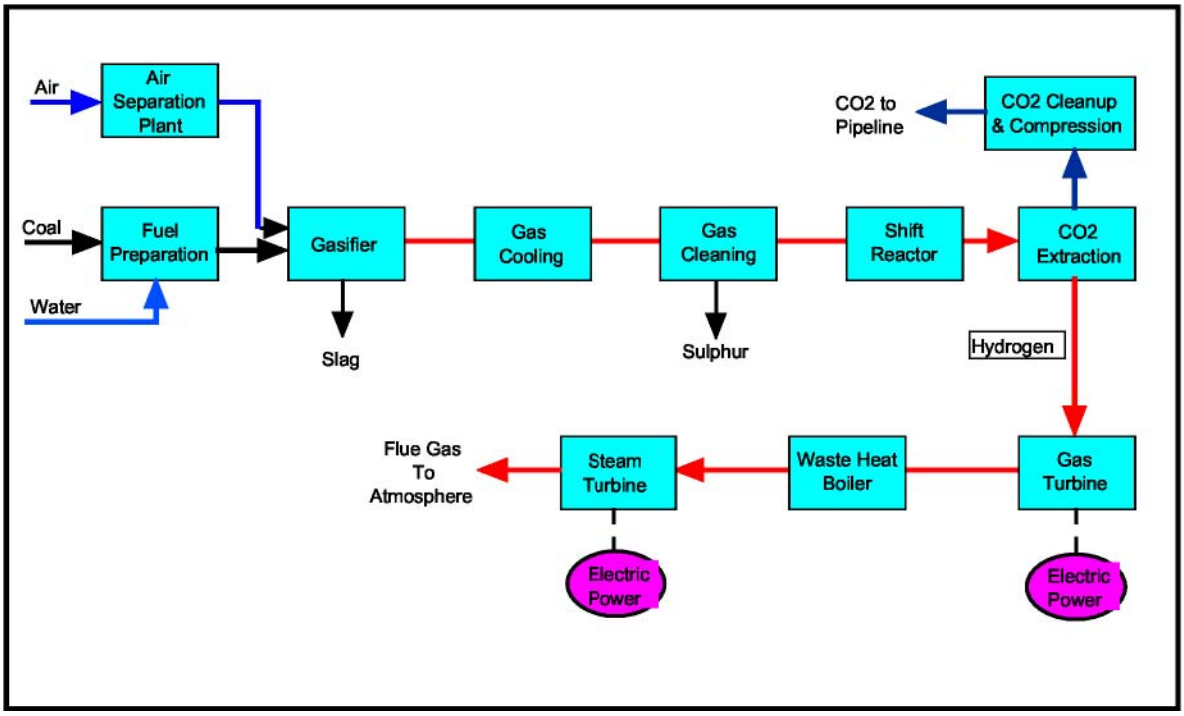

Figure 3 Coal gasification

A qualitative technology evaluation was initially conducted of the various units that were considered be suitable for incorporation in a gasification-based plant. These technology options were then narrowed down to those that show performance and cost advantage over the alternative technologies, and also are available in the time frame being considered for the demonstration plant. The resulting recommended overall plant configuration consists of an oxygen blown Integrated Gasification Combined Cycle (IGCC) plant. Four gasification technologies: E-Gas, Noell, Shell and ChevronTexaco, were analyzed to provide CCPC a basis for selection of the appropriate gasification technology.

The first three gasification processes above were evaluated for all three coals, while the ChevronTexaco process was evaluated for the bituminous and subbituminous coals only. ChevronTexaco stated that they do not consider their process suitable for the lignite feedstock due to its very high inherent moisture content. Each of these oxygen blown gasification units is integrated with a combined cycle consisting of two General Electric 7FA+e gas turbines. The CO contained in the syngas produced by the gasification process is reacted with steam in sour shift reactor(s) to form CO_2; 80 to 90 per cent of the CO_2 is then removed along with the sulphur compounds in a Selexol unit.

The mostly decarbonized clean syngas is fired in the gas turbines. The recovered CO_2 is compressed to 13800 kPa(g) prior to feeding it to a pipeline. Other effluents generated by the plant are elemental sulphur, low CO_2 content flue gas (from the combined cycle), slag and wastewater.

It is worth noting that Shell and Noell feed the gasifier with dried and pulverized fuel. Low rank coal contains large amounts of moisture, and drying it consumes a significant amount of energy. The thermal efficiency of plants using such fuels can be enhanced by drying the feedstock under pressure utilizing high pressure nitrogen produced by the air separation unit (or high pressure syngas). In turn, the effluent gas from the dryer with its accompanying moisture is returned to a gas turbine (after the moist gas is preheated and passed through a particulate filter). In this manner, the large amount of heat utilized by the drying operation, which tends to limit the overall thermal efficiency of the IGCC, does not become a thermal penalty on the process. The added moisture also decreases the NO_X emissions from the gas turbine. The net result is a process that shows a significant improvement in the plant net heat rate for the subbituminous coal and the lignite. This was the process evaluated by CCPC.

The results of the gasification selection stage are summarized in Table 5:

Table 5 Gasification technology selection results

Fuel	Units	Bituminous	Subbituminous	Lignite
Technology		ChevronTexaco	ChevronTexaco	Shell
Carbon Recovery	%	1.2	85.6	85.7
Efficiency (HHV)	%	29.88	25.39	24.03
Capital Cost	Millions $CAD	1,774	2,095	2,317
Cost of Electricity	$/MWhr	76.5	69.29	86.82
Capacity	MWnet	13	428	402

The first stage in the evaluation of amine scrubbing and oxyfuel combustion was a site selection study which compared retrofit of CO_2 capture at the three chosen power plants, with the aim of selecting one plant for a more detailed site optimisation study.

Results of the site selection studies are summarised in the CCPC's own summary report, which is attached to this overview. The studies showed that the Genessee plant is the most attractive for a capture retrofit as it has the lowest projected costs of CO_2 capture and electricity generation and has the greatest potential for utilisation of captured CO_2. However, the Shand site, which was the second best option, was selected for the more detailed site optimisation study, because of the ease of obtaining plant design data within the time frame of the study. Although Shand was not the preferred site it would be suitable for a retrofit or new power plant because there is plenty of plot space available and the existing infrastructure was designed with a second plant in mind. The existing Shand power plant is relatively modern, having been commissioned in 1992.

The specification for the site selection studies required that there should be no net loss of power sent out due to CO_2 capture retrofit. This was achieved by constructing an auxiliary coal fired boiler with CO_2 capture. The auxiliary boilers were found to be similar in size to the original power plant boilers. This was not considered to be an attractive option because the auxiliary power plant would have a lower efficiency than a greenfield power plant, less favourable economies of scale and the overall cost of a retrofit would probably be close to that of a greenfield power plant. The study also showed that there are significant opportunities to optimise the efficiency of an amine scrubbing plant by integration with the power plant. This may be more difficult to achieve in a retrofit than in a new plant. In the case of oxyfuel combustion the study showed that air infiltration was a major issue, as it would increase the concentration of inert gases in the CO_2 product, which would increase the cost of the product recovery and compression unit. A new power plant could be easily designed to have much lower air infiltration rates than existing plants. The site selection study also confirmed that the energy efficiency penalty for CO_2 capture would be substantial. This highlighted the need for the basic power cycle to have as high an efficiency as possible, which could only be achieved in a new plant. For these reasons, the CCPC decided that the more detailed site optimisation work should concentrate on greenfield plants for all technologies. An amine scrubbing retrofit at the Shand site was also evaluated but it did not include construction of an auxiliary boiler to offset the reduction in net power output.

The evaluation of amine scrubbing in the site selection study did not consider detailed integration between the existing plant and the retrofitted units. It was also based on Fluor's original Econamine FG^{SM} process rather than their improved Econamine FG Plus^{SM} process which became available during the course of the study. The heat consumption of the Econamine FG Plus^{SM} process is 21% lower than that of the conventional Econamine FG^{SM} process and the solvent degradation loss is substantially reduced. This is achieved mainly by split flow solvent circulation, improved solvent formulation, better heat integration and vacuum reclaiming of solvent. Heat integration with the vacuum condensate of the steam cycle brings the overall reduction in heat consumption to 32%.

The results of the detailed evaluations of retrofit and greenfield plants with amine scrubbing are shown in Table 6.

Table 6 Comparison of retrofit and greenfield plants with CO_2 capture (lignite/fuelled)

Plant performance	**Retrofit**	**Greenfield**
Gross power output, MW	304.4	453.5
Boiler auxiliary power consumption, MW	26	21.4
Power loss due to CO_2 capture and pollutant control, MW	84.6	121.2
Net power output, MW	193.8	310.9
Thermal efficiency, %LHV	25.26	31.80
Costs		
Capital cost, US$/kW net output	1005	2826
US$/t CO_2 avoided	55.0	36.3

The thermal efficiency of the retrofitted Shand lignite-fuelled plant with CO_2 capture is significantly lower than that of a greenfield power plant at the same location. This is mainly because the existing Shand power plant has a lower efficiency steam cycle (12.6 MPa, 538/538C steam conditions, compared to 24.2 MPa, 593/593C in the greenfield plant).

The capital cost of US$1005/kW shown in Table 6 for the retrofit is only the cost of the retrofitted CO_2 capture and other emission control equipment and does not take into account the cost of new generating capacity which would have to be built elsewhere to make-up for the reduction in net power output due to CO_2 capture.

The overall cost of CO_2 capture, in $/tonne of CO_2 emissions avoided, is higher in the retrofit plant than the greenfield plant. For this overview, the make-up power for the retrofit plant is assumed to be provided by a new large coal-fired power plant with CO_2 capture, such as the greenfield plant shown in Table 6. The quantity of CO_2 avoided is the emissions of the Shand plant without capture minus the sum of the emissions from the plant with capture and the emissions from the make-up power plant.

The greenfield plant is larger than the retrofit plant, giving it better economies of scale. This accounts for less than half of the difference in the cost of capture. In the CCPC study the retrofit and greenfield plants were both evaluated with a plant life of 20 years. In practice the operating life of a retrofitted plant is likely to be lower than that of a greenfield plant, so the capital cost of the capture equipment would have to be recovered over a shorter period of time, resulting in a higher cost of capture.

A conclusion of this assessment is that where new coal-based generating capacity is needed and there is a need to capture CO_2 it will be preferable to install CO_2 capture in the new plants rather than in retrofits. However, there may be circumstances in which retrofits would be attractive. If the requirement to install CO_2 capture is greater than the requirement for new generating capacity, there would be a choice between retrofitting CO_2 capture to existing plants or prematurely retiring existing plants and replacing them with new plants with CO_2 capture. The optimum choice would depend on local circumstances. If the marginal operating costs of the existing plants were high and their remaining lifetimes were short, premature retirement of existing plants and construction of new plants would be preferred. Evaluation of retrofits to very old power plants is beyond the scope of this study (the Shand plant evaluated in this study is only about 10 years old).

5 CO_2 capture at greenfield plants

The gasification technology evaluation concentrated from the start on greenfield sites. The first stage was a screening evaluation to select gasification processes for each of the coals. ChevronTexaco, Shell, E-Gas and Noell gasification processes were assessed. ChevronTexaco gasification with water quench of the product gas was selected for bituminous and subbituminous coals, as it gave the lowest cost of electricity generation, and Shell gasification with product gas heat recovery was selected for lignite. ChevronTexaco stated that their process was not appropriate for lignite due to lignite's high inherent moisture content. The cost of electricity in the ChevronTexaco gasifier plant using bituminous coal was about 10% lower than in the comparable Shell gasifier plant.

Detailed evaluations were then carried out for bituminous and subbituminous coal-fuelled plants based on ChevronTexaco gasifiers and a lignite-fuelled plant based on Shell gasification. The plants were based on 2 GE7FA gas turbines, resulting in net power outputs of around 400 MW. The costs of CO_2 emission avoidance were calculated compared to pulverised fuel fired reference plants. These plants used supercritical steam conditions and included FGD, SCR, and mercury and particulate removal. Performance and cost data for the IGCC plants with CO_2 capture and the pulverised fuel reference plants are shown in Table 7.

Table 7 Greenfield plant evaluation

	Bituminous	**Subbituminous**	**Lignite**	**Lignite**	**Lignite**
Plants with CO_2 capture					
Technology	Gasification	Gasification	Gasification	Amine	Oxyfuel
Net power (MW)	444.5	436.8	361.1	310.9	373
Efficiency, % (LHV)	32.97	27.71	30.00	31.80	26.69
CO_2 captured (%)	87.0	92.0	85.7	95.0	90.0
CO_2 emitted, g/kWh	130	102	182	60	145
Capital cost (US$/kW)	1917	2190	2828	2824	3974
COE (USc/kWh)	6.84	6.21	8.39	7.43	9.74
Reference pulverised fuel plants without capture					
Net power (MW)	424.5	424.5	424.5	424.5	424.5
CO_2 emissions (g/kWh)	771	852	883	883	883
Efficiency, % (LHV)	42.94	42.37	43.43	43.43	43.43
Capital cost (US$/kW)	1410	1502	1644	1644	1644
COE (USc/kWh)	4.87	3.73	4.45	4.45	4.45
CO_2 capture plants compared to pulverised fuel plants					
CO_2 emissions avoided, g/kWh	641	750	701	823	738
Efficiency penalty for capture, %	9.97	14.66	13.43	11.63	16.74
Capital cost penalty, US$/kW	507	688	1184	1180	2330
Electricity cost penalty, USc/kWh	1.97	2.48	3.94	2.98	5.29
CO_2 avoided cost, US$/t CO_2	31	33	56	36	72

Detailed evaluations of new lignite fired plants with amine scrubbing and oxyfuel combustion were also carried out. These plants were based on the supercritical steam conditions used in the reference plants. The amine scrubbing plant was based on Fluor's Econamine FG Plus^{SM} process. The oxyfuel combustion plant was based on a boiler designed for low air infiltration.

The efficiencies of the reference pulverised coal plants are lower for lower rank coals, mainly because of lower boiler efficiencies. The specific emissions of CO_2 are higher for lower rank coals because of the lower efficiencies and because the specific carbon contents (kg C/MW of thermal energy) of lower rank fuels are higher, as shown in Table 2. The capital costs are also higher for lower rank coals. The cost of generation depends on the fuel cost, which in the Canadian context is lowest for subbituminous coal, as shown in Table 2. The overall cost of generation is lowest for subbituminous coal.

In general the IGCC plants with CO_2 capture show the same trends. An exception is that the lignite-fuelled plant has a higher efficiency than the bituminous coal plant. This is because the lignite plant is based on the Shell gasifier, which uses a dry coal feeding system and a heat recovery boiler, and the other plants use the ChevronTexaco quench gasifier, which uses a water slurry feed system and water quench cooling of the product gas. The specific emissions are lowest in the subbituminous coal-fuelled plant for detailed design reasons. The additional cost of generation due to CO_2 capture and the cost of CO_2 emissions avoidance are higher for lower rank coals, for example the cost of emission avoidance in the lignite-fuelled plant is twice as high as in the bituminous coal-fuelled plant.

For lignite-fuelled plants, the lowest cost CO_2 capture option, by a substantial margin, is amine scrubbing, followed by gasification, and the most expensive option is oxyfuel combustion. This is despite the fact that in this study the amine scrubbing plant has the smallest net power output and therefore the least favourable economies of scale. If the plants all had the same net outputs, amine scrubbing would be cheapest by a greater margin. The amine scrubbing plant has further advantages; it has the highest thermal efficiency and the highest percentage CO_2 capture. The CO_2 capture rate in the amine scrubbing plants is 95%, which is higher than in the other plants. 85% CO_2 capture was assessed by the CCPC in a sensitivity study and it was found to increase the cost of CO_2 avoided by 2%. The sensitivity of cost to percentage CO_2 capture was not assessed for the other technologies but it appears unlikely that a higher percentage CO_2 capture would have significantly reduced the specific cost of capture.

Although gasification was shown to have a higher cost than amine scrubbing, the technology for lignite gasification is relatively immature and there is significant scope for improvements.

Oxyfuel combustion was shown to be the highest cost option but substantial improvements could be made to the design adopted in the CCPC studies. The oxyfuel combustion studies specified that the plants should retain full air firing capability, which resulted in high flow rates through the emission control equipment. Although this gives some operability advantages, it significantly increases costs. The boilers were designed to have an inlet oxygen concentration similar to that of air but pilot scale research has shown that oxyfuel boilers could have an inlet oxygen concentration of about 30%, which would substantially reduce the boiler and recycle gas flowrates, and hence the plant costs. There are also further opportunities to improve the efficiency and costs by optimising the flue gas cooling. Another option which could be advantageous particularly for the Saskatchewan lignite would be cyclone firing, which would greatly reduce the size of the boiler. Cyclone boilers are a proven technology but they have not been used much in recent years because of high NO_x emissions. However, this is much less of a concern in oxyfuel combustion.

The CCPC study is based on the Canadian coal prices shown in Table 2. Coal prices may be different in different countries, leading to different relative costs of generation for different fuels. The sensitivity of electricity cost to coal price is shown in Figure 4. Note these costs still include some site-specific costs for each fuel which may not apply in other locations.

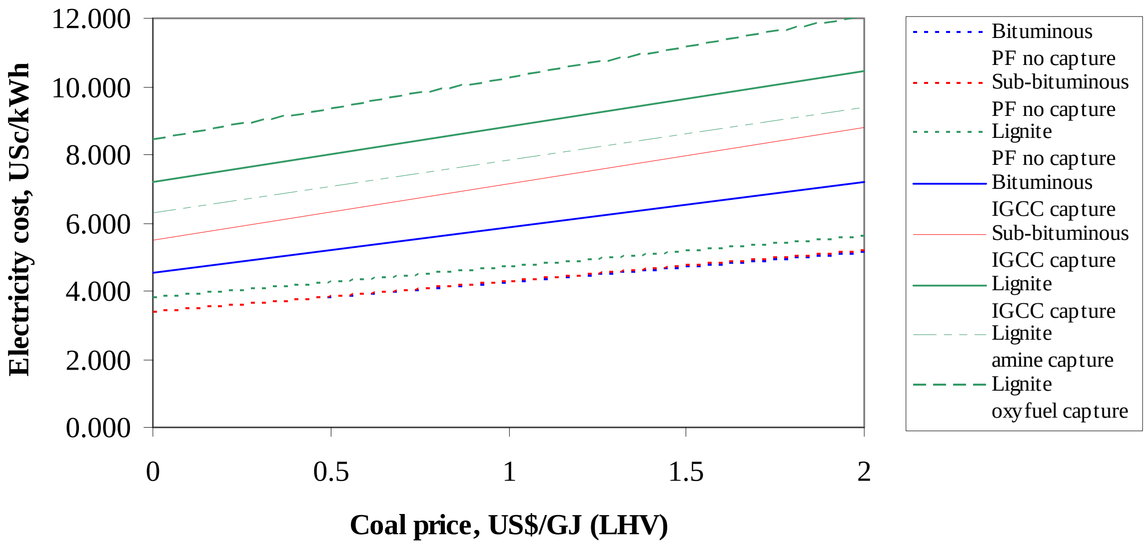

Figure 4 Sensitivity of electricity cost to fuel price

6 CO_2 storage and utilisation

Two studies on CO_2 storage and utilisation were carried out:

- a compilation and evaluation of CO_2 utilisation and storage options in Western Canada, and
- an evaluation of the potential to store CO_2 in coal deposits in Nova Scotia

The study on Western Canada reviewed all storage and utilisation options and concluded that the only viable options were enhanced oil recovery (EOR), enhanced coal bed methane production (ECBM) and geological storage in depleted oil and gas fields and aquifers. The study concluded that the preferred storage option is EOR. While there do not appear to be any technical obstacles in general to EOR and storage in depleted oil and gas reservoirs and aquifers, there would be many questions for any specific project. ECBM is immature and is unlikely to proceed without significant technical development and pilot scale projects. Major uncertainties include permeability, gas content and CO_2 absorption ratios.

An EOR project taking CO_2 from a 400 MW power station would be one of the largest EOR operations in the world. It was determined that there could be 5 or 6 viable EOR projects in Alberta with sufficient capacity to store CO_2 from a commercial scale power plant over a 30 year life. Opportunities in Saskatchewan are much more limited and only one EOR project would be viable.

The cumulative investment for an EOR project taking CO_2 from a 400 MW power station (2.6 Mt/y) was estimated to be about US$600 million spread over the life of the project. The estimated investment cost for storage in depleted oil and gas reservoirs was about US$30 million. The cost of storage in deep saline aquifers was expected to be of the same order as storage in depleted oil and gas reservoirs, but probably slightly higher on average due to infrastructure requirements and generally higher initial formation pressures.

The CCPC estimated breakeven values for CO_2, i.e. the maximum that the storage operator could pay for CO_2, based on a 15% economic discount rate, an oil revenue of US$20/barrel and a natural gas revenue of about US$2.7/GJ (LHV). The breakeven values of CO_2 were US$27/tonne for EOR, US$6/t for ECBM and minus US$2.5/t for depleted oil and gas reservoirs. These figures do not take into account taxes and royalties. An EOR project would emit CO_2 equivalent to about 7-8% of the CO_2 delivered, mainly due to on-site gas recompression, although this could probably be reduced by optimising the gas/CO_2 separation. This CO_2 emission was not taken into account in the assessment.

CO_2 purity is a critical issue for EOR. Relatively low levels (1-2%) of N_2, O_2 or CO could potentially have a negative impact on EOR recovery, by increasing the minimum miscibility pressure. O_2 could also oxidise the oil making it more viscous and difficult to refine. H_2S and SO_2 would have the beneficial effect of reducing the minimum miscibility pressure, although a mixture of CO_2 and SO_2 might cause the deposition of elemental sulphur in a reservoir containing H_2S.

The study by the Geological Survey of Canada identified that there is significant potential for coalbed methane production and storage of CO_2 in the coalfields of Nova Scotia. Further work involving field testing is needed to investigate this potential further.

7 Conclusions

The cost of capturing CO_2 in a new coal fired power plant would be lower than in an existing coal-fired power plant retrofitted with CO_2 capture. Retrofit would only be attractive if all new coal-fired power plants were being fitted with CO_2 capture and there was a need to achieve even greater emission reductions.

The choice of CO_2 capture technology and the cost of capture depend highly upon coal rank.

The thermal efficiency and cost penalties for CO_2 capture in IGCC are higher for lower rank coals. However, based on Canadian coal prices, a subbituminous coal-fuelled plant with CO_2 capture would have the lowest cost of electricity generation.

For lignite-fuelled plants, the costs of electricity generation and CO_2 capture are significantly lower for amine scrubbing than for IGCC or oxyfuel combustion.

Costs of CO_2 capture could be reduced by more design optimisation, particularly for oxyfuel combustion.

The preferred option for CO_2 storage in western Canada is EOR.

CCPC Phase I Executive Summary

Summary Report on the Phase I Feasibility Studies
conducted by the
Canadian Clean Power Coalition

May 2004

Acknowledgements

The Canadian Clean Power Coalition wishes to acknowledge the financial contributions made by Natural Resources Canada, Alberta Energy Research Institute and Saskatchewan Industry and Resources to the Phase I studies.

Introduction

The Canadian Clean Power Coalition (CCPC) represents electricity generators and coal suppliers of over 90% of Canada's coal-fired power generation. The participants of the CCPC have been concerned about the level of greenhouse gas emissions resulting from the operation of their plants. As the challenge of potential climate change impacts became clear, coal and coal fired electricity producers began to evaluate strategies for net emission reduction.

A number of the participants held a series of discussions throughout 2000 and 2001 to identify a joint course of action to ensure that coal and coal fired electricity would continue to have a place in Canada's energy supply future, alongside both other conventional fuels and non-conventional renewable supplies. These discussions expanded and culminated in the formation of the CCPC, an association and formal agreement.

The CCPC Participation Agreement was signed in mid 2001 among ATCO Power Canada Ltd., EPCOR Utilities Inc., Luscar Limited, Nova Scotia Power Inc., Ontario Power Generation Inc., Saskatchewan Power Corporation, and TransAlta Utilities Corporation, with the concept of a private-public partnership to develop technology to meet the stated goals. Phase I of the project commenced in September 2001. Subsequently, the governments of Alberta, Saskatchewan, and Canada subscribed to support the CCPC. In addition, the participation of EPRI (Electric Power Research Institute of Palo Alto, CA) and IEA (International Energy Agency) was solicited and secured.

The CCPC established a goal to develop projects to demonstrate technology at a commercial utility scale for retrofit to existing plants, or for use in new coal fired power plants, that would allow all emissions, including CO_2, to be controlled to meet all foreseeable new regulatory requirements. The emissions target was to allow a coal-fired plant to be as clean as a modern natural gas fired gas turbine plant. The goal was to do this while maintaining overall efficiency at or above current levels, maintaining costs competitive with other generation technologies and enabling the CO_2 to be captured.

Phase I of the project comprised the Conceptual Engineering and Feasibility Studies, undertaken from mid 2001 to early 2004. The objective of the conceptual engineering and feasibility studies was to determine the most appropriate technologies for demonstration. Implementation plans, preliminary designs and cost estimates were developed for those technologies, recognizing the geographical variability of coal: western lignite and sub-bituminous coals, and eastern bituminous coals.

The fundamental principle underlying the goals of the CCPC was to identify a process that would produce electricity from coal in some fashion and that would also provide a relatively pure stream of CO_2 that could be captured, further processed as necessary, and subsequently used or stored.

Work Packages

Table 1 summarizes the work packages that were used to complete the Phase I effort. The CCPC requested potential contractors to submit proposals on the various work packages. These proposals were evaluated by the CCPC and contracts were awarded to carry out the work.

Table 1: WORK PACKAGE DESCRIPTIONS

Number	Description	Contractor	Completion Date
WP1	Pre-screening study	SFA Pacific	December 2001
WP2	Amine scrubbing and oxyfuel evaluation	Fluor Canada	July 2003
WP3	Gasification technologies evaluation	Fluor Canada	July 2003
WP4	Retrofit emissions control except CO_2	Neill & Gunter	December 2002
WP5a	CO_2 utilization and storage options in western Canada	SNC Lavalin	August 2003
WP5b	CO2 sequestration opportunities in Nova Scotia coal seams	Geological Survey of Canada	March 2004
WP6	Phase I final report	CRI Consulting	February 2004

Results

The main results of the feasibility studies are summarized in Table 2. Much detailed analysis has been conducted in order to develop these data.

Table 2: TECHNICAL AND ECONOMIC COMPARISON OF CO_2 ABATEMENT TECHNOLOGIES

Fuel		Bituminous	Sub-bituminous	Lignite	Lignite	Lignite
Technology		Gasification	Gasification	Gasification	Amine	Oxyfuel
COE (90%CF)	$/MWhr	**107**	**97**	**131**	**116**	**152**
Cost	millions $	1,330	1,490	1,590	1,370	2,310
CO_2 Emitted	Tonne/MWhr	0.116	0.111	0.182	0.060	0.145
CO_2 Captured	%	86	89	86	95	90
CO_2 Avoided	Tonne/MWhr	0.65	0.74	0.71	0.82	0.74
Cost CO_2 Avoided*	$/tonne	47	52	88	57	112
Capacity	MW gross	594	629	555	454	629
Economic Capacity	MW net	445	437	361	311	373
Net Heat Rate	KJ/kWhr	11,410	13,810	13,240	12,530	14,880
Unit Cost	$/kW net	3,000	3,400	4,400	4,400	6,200

*Note to Table 2. Cost of CO_2 avoided is defined as the increase in cost of electricity in $/MWhr (evaluated case minus selected base case) divided by the decrease in tonnes of CO_2 emitted per $MWhr_{net}$ (selected base case minus evaluated case).

Conclusions and Next Steps

The learnings from Phase I were:

- This was the first study to assess all three available technologies for CO_2 capture.
- Emissions from coal can be reduced to levels equivalent to natural gas power generation.
- The cost of electricity (COE) with CO_2 capture was 50% higher than current rates, but lower than prior studies.
- Gasification ranked first and amine scrubbing next, even with non-optimized processes.
- The Western Canada Sedimentary Basin has vast storage capacity for CO_2.

The set of conclusions that the CCPC has adopted as a result of the work of Phase I are itemized below.

- Gasification is still not mature technology for power plant applications. Significant work remains to be undertaken to make this a competitive technology, although it is probably the most likely platform for the future if limits on CO_2 emissions are applied. Similarly, oxyfuel is not yet a mature technology. Amine scrubbing would appear to be relatively mature, one of the lowest cost alternatives, and ready to apply to power plant applications for capturing CO_2. Initiatives are required:
    - To explore and develop gasification for low ranked coals to make it more reliable and cost effective, and
    - To answer scale up questions regarding amine scrubbing.
- A demonstration project will require a substantial effort from industry and government if it is to proceed and to succeed. Government participation will be required to ensure that such a project can be financed, to ensure that the necessary permitting is provided, and to provide significant funding.

Detailed studies of IGCC plants will be conducted in Phase II prior to making commitments for demonstration projects. The studies should include considerations of polygeneration of power, hydrogen, and steam at Saskatchewan (lignite-fueled) and Alberta (sub-bituminous-fueled) sites, where business cases might be built based on partnerships with nearby oil refineries and other industries. Those refineries could supply low-cost petroleum coke for fuel blending and potentially could utilize the polygenerated hydrogen and steam. An IGCC plant designed for co-production of hydrogen is inherently ready for the addition of CO_2 capture equipment. Phase II will optimize the technologies to lower costs further and develop the right business case for the demonstration plant. It appears that a CO_2 capture project is most likely to be a greenfield project because CO_2 capture technologies are not sufficiently attractive on a retrofit project.

In summary, power generators using coal-fired generation see an array of new emissions regulations approaching in the next few years. There is an urgent need to understand and evaluate the ability for advanced combustion and emissions control technologies to mitigate the environmental impact of coal-derived power generation before committing the significant capital investment necessary to construct the necessary plant. The Canadian Clean Power Coalition is one such response. The participants anticipate that the results of the studies will make a significant contribution to the understanding of the control of air emissions, including CO_2, from the generation of power from coal.