A Comparison of Combustion Technologies for Electricity Generation

2006 Update Including a Discussion of Carbon Capture and Storage in an Ontario Context

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Rich Wong
Ed Whittingham

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Notes to the Reader

Acronyms and Abbreviations

AFBC	Atmospheric Fluidized Bed Combustion
CAC	Criteria Air Contaminants (NOx, SOx, PM, VOCs, CO)
CCPI	Clean Coal Power Initiative
CCS	Carbon Capture and Storage
CO	Carbon Monoxide
CO_2	Carbon Dioxide
COE	Cost of Electricity
DOE	U.S. Department of Energy
ESP	Electrostatic Precipitators
FGD	Flue Gas Desulphurization
H2S	Hydrogen Sulfide
HHV	High Heating Value
IGCC	Integrated Gasification Combined Cycle
LHV	Low Heating Value
LNB	Low NOx Burners
MW	Megawatt
NG	Natural Gas
NGCC	Natural Gas Combined Cycle
NOx	Oxides of Nitrogen
PCC	Pulverized Coal Combustion
PFBC	Pressurized Fluidized Bed Combustion
PM	Particulate Matter
SCR/SNCR	Selective Catalytic Reduction/Selective Non-catalytic Reduction
SOx	Oxides of Sulphur
VOCs	Volatile Organic Compounds

Executive Summary

This report updates the Pembina Institute's 2001 publication *A Comparison of Combustion Technologies for Electricity Generation*, republished in 2004 as Appendix 4 in *Power for the Future: Towards A Sustainable Electricity System in Ontario.*[1]

The electricity generation technologies examined include the following:

- High-efficiency coal combustion technologies: Pulverized Coal Combustion (PCC), Atmospheric Fluidized Bed Combustion (AFBC), Pressurized Fluidized Bed Combustion (PFBC), and Integration Gasification Combined Cycle (IGCC).
- "End-of-pipe" or add-on pollution control options for coal such as Flue Gas Desulphurization (FGD), Low NOx Burners (LNB), Selective Catalytic or Non-Catalytic Reduction (SCR/SNCR), Electrostatic Precipitators (ESP) and Baghouses.
- Natural gas-fired options: Natural Gas Combined Cycle (NGCC) and Combined Heat and Power.

The review concludes that none of the coal-fired options are as environmentally favourable as the natural gas-fired options. Among the coal-fired options, IGCC showed the best opportunity for environmental performance, although it still has high CO2 emissions relative to natural gas-fired options.

The review also notes that IGCC technologies may theoretically be combined with carbon capture and storage (CCS) technologies. However, the review concludes that carbon storage options for Ontario are unproven and speculative, and that, given the extent of the research required to demonstrate their viability, they cannot be considered a serious possibility within the current 20-year electricity policy planning horizon.

[1] Mark S. Winfield, Matt Horne, Theresa McCleneghan and Roger Peters, *Power for the Future: Towards A Sustainable Electricity System for Ontario* (Toronto: The Pembina Institute and Canadian Environmental Law Association, 2004), www.pembina.org/pdf/publications/energyreport-fullreport_a.pdf.

1.0 Introduction

1.1 Report Context and Goals

In May 2004 the Pembina Institute and the Canadian Environmental Law Association jointly published *Power for the Future: Towards a Sustainable Electricity System for Ontario.*[2] Included in the report was *Appendix 4: A Comparison of Combustion Technologies for Electricity Generation*, itself originally published in 2001. That appendix, the key findings of which are reproduced here as Appendix 1, included a review of the economic and environmental performance of a range of coal and natural gas combustion technologies for electricity generation.

These technologies included the following:

- Higher-efficiency coal combustion technologies, such as Pulverized Coal Combustion (PCC), Atmospheric Fluidized Bed Combustion (AFBC), Pressurized Fluidized Bed Combustion PFBC, and Integration Gasification Combined Cycle (IGCC).
- "End-of-pipe" or add-on pollution control options for coal such as Flue Gas Desulphurization (FGD), Low NOx Burners (LNB), Selective Catalytic or Non-Catalytic Reduction (SCR/SNCR), Electrostatic Precipitators (ESP) and Baghouses.
- Natural gas-fired options, such as Natural Gas Combined Cycle (NGCC) and Combined Heat and Power.

The 2001 review found that none of the coal-fired options were as environmentally favourable as the natural gas-fired options. Among the coal-fired options, IGCC showed the best opportunity for environmental performance, although it still had high CO2 emissions relative to natural gas.

In light of Ontario's recent retreat from the coal-phase out plan originally scheduled to be completed by 2009, but now deferred, this paper updates the 2001 combustion technology analysis. In particular, it investigates the current commercialization status and performance of IGCC technology for power generation, as this is the most significant area of change relative to the original 2001 analysis. The report also explores the possibilities of greenhouse gas (GHG) capture and storage in Ontario, as a means of managing GHG emissions associated with fossil fuel-fired electricity generation.

1.2 Study Methodology

To prepare the report, researchers drew upon secondary sources (reports, journal articles, etc.) and conducted interviews with select government, industry and academic representatives. It is important to note that, while the report outlines the environmental and economic performance of combustion technologies for electricity generation, it does not address the environmental or economic impacts of coal or natural gas extraction, production, and delivery systems.

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[2] Mark S. Winfield, Matt Horne, Theresa McCleneghan and Roger Peters, *Power for the Future: Towards A Sustainable Electricity System for Ontario* (Toronto: The Pembina Institute and Canadian Environmental Law Association, 2004), www.pembina.org/pdf/publications/energyreport-fullreport_a.pdf.

2.0 An Overview of Combustion Technologies for Electricity Generation[3]

All coal combustion technologies rely on the generation of high pressure steam using heat produced by burning coal. This high pressure steam then drives a turbine, which is attached to an electrical generator and produces electricity.

Exhaust gases from combustion of the coal are typically cleaned by a series of processes. Particulates are removed by electrostatic precipitators or fabric filters (baghouses), and sulphur oxides (SOx) are removed by one of a range of possible flue gas desulphurization (FGD) processes. Nitrogen oxide (NOx) production can be controlled by in-furnace features such as low NOx burners. A Selective Catalytic or Non-Catalytic Reduction process can further reduce NOx emissions.

The combustion of coal in the boiler can be accomplished in various ways, described below. In general, the most energy-efficient plants have the lowest emissions, as they produce more electricity per unit of coal burned. However, emissions from less-efficient plants can be reduced with “add-on” pollution control options.

2.1 Subcritical and Supercritical Pulverized Coal Combustion (PCC)

Coal combustion has traditionally occurred at atmospheric pressure to produce subcritical steam, but today, greater efficiencies can be obtained by using higher steam pressures in the supercritical range.[4] Both subcritical and supercritical processes begin with coal being ground into a fine powder. The powdered coal is blown with air into the boiler through a series of burner nozzles where combustion takes place at temperatures from 1,300–1,700°C, depending largely on the coal type. Combustion occurs at near-atmospheric pressure, which simplifies the burner and coal handling facilities. Subcritical pulverized coal combustion (PCC) plants use steam in the range of 16 megapascals (MPa) pressure and at 550°C while supercritical PCC plants use steam with pressures as high as 30 MPa and at 600°C. The higher steam pressure in supercritical plants results in higher energy efficiency of 38–45%, compared with 33% for subcritical plants. However, supercritical plants have higher capital costs and some added risk due to the higher pressure and temperature. They have only come into commercial service in Canada recently.[5]

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[3] Description of technologies adapted from Winfield, Horne, McClenaghan and Peters, “Power for the Future,”Appendix 4, 171–184.

[4] At atmospheric pressure, water bubbles at boiling point before turning into steam; above a certain critical pressure, it enters a “supercritical” state, where it undergoes a continuous transformation directly into steam.

[5] The first such facility in Canada, EPCOR’s Genesee Facility, came into service in 2006.

2.2 Atmospheric and Pressurized Fluidized Bed Combustion (AFBC and PFBC)

Fluidized bed combustion (FBC) processes are commonly used with high sulphur coal. In an FBC plant, hot air blown up through the floor of the boiler suspends or "fluidizes" powdered coal mixed with a sorbent such as powdered limestone. The combustion of the coal in the presence of the sorbent facilitates the capture of sulphur dioxide (SO_2). Conventional boilers, by contrast, simply burn the fuel on a grate in the firebox. FBC plants can remove up to 98% of the SO_2 and the coal burns more efficiently because it stays longer in the combustion chamber.

Atmospheric fluidized bed combustion (AFBC) plants operate at atmospheric pressure, and NOx generation is minimized due to lower combustion temperatures (815–875°C) than in conventional PCC plants. In contrast to AFBC plants, pressurized fluidized bed combustion (PFBC) plants operate at elevated pressures. PFBC plants are typically more compact than similar capacity AFBC and PCC plants due to the higher pressure. The PFBC design allows for potentially greater efficiency, reduced operating costs and less waste than the AFBC design. PFBC plants use the same process as AFBC plants to fluidize or float the coal/sorbent mixtures. In both AFBC and PFBC plants, the reacted sorbent forms a dry, granular material that is easily disposed of or used as a commercial by-product. The reacted sorbent is removed with the bed ash through the bottom of the boiler and with the fly ash that has been collected in the dust collectors at the top of the boiler stacks.

In PFBC plants, additional energy is captured when the combustion gases that leave the fluidized bed are cleaned in a gas cleanup system and then re-burned in a gas turbine. The gas turbine is connected to an electrical generator thereby improving the plant's efficiency. The use of a steam turbine and a gas turbine improves performance by creating a highly efficient combined cycle system.

The operating temperatures of fluidized beds are between 760 and 870°C, approximately half the temperature of a conventional boiler. This relatively low temperature is below the threshold where thermally induced NOx forms. Thus, the fluidized bed designs have reduced SO_2 and NOx emissions compared to PCC designs. In addition, fluidized bed combustion can use high-ash coal whereas conventional pulverized coal units must limit ash to relatively low levels.

2.3 Integrated Gasification Combined Cycle (IGCC)

IGCC plants are potentially cleaner and more efficient than traditional coal-fired systems. In IGCC plants, coal is not burned in a traditional boiler but is converted into a hydrocarbon vapour (syngas) in a gasifier. The syngas (principally hydrogen (H_2) and carbon monoxide (CO)) then undergoes a gas-water shift, converting the CO to CO_2 and producing and forming more H_2. Lastly the H_2 is separated from the CO_2. The H_2 can then be used instead of natural gas as fuel in a conventional combined cycle plant (see below for a description of the natural gas combined cycle plant), while the CO_2 can be compressed for transport and storage. The result is an integrated gasification combined-cycle configuration that offers the potential for lower pollution levels and high system efficiencies, while facilitating the possibility of carbon capture and storage (CCS).[6] The combination of IGCC with CCS, however, has not yet been put into practice.

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[6] For a detailed discussion of these processes see Mary Griffiths, Paul Cobb and Thomas Marr-Laing, *Carbon Capture and Storage: An Arrow in the Quiver or a Silver Bullet to Combat Climate Change? — A Canadian Primer* (Drayton Valley, AB: The Pembina Institute, 2005), 24–26. www.pembina.org/pdf/publications/CCS_Primer_Final_Nov15_05.pdf.

2.4 Natural Gas Combined Cycle (NGCC)

While the natural gas combined cycle process (NGCC) is not a coal combustion process, it is included here for the purpose of comparison with the various coal-fired options. Commercial-grade natural gas burns more cleanly than other fossil fuels because it consists mostly of methane and has already been cleaned of sulphur. In NGCC plants, natural gas is used as fuel in a gas turbine. Electricity is produced from the generator coupled to the gas turbine, and the hot exhaust gas from the turbine is used to generate steam in a waste heat recovery unit. The steam is then used to produce more electricity in the same way as described for the PCC options above. The output from both the gas turbine and the steam turbine electrical generators is combined to produce electricity very efficiently. NOx control in gas turbines is proven technology and can be accomplished with relatively inexpensive "low NOx burners." In addition, NOx can be reduced still further with such "add-on" control technology as Selective Catalytic Reduction. Emissions of particulate matter generated with this method are also quite low, although some secondary particulate matter is produced through atmospheric chemistry reactions involving NOx.

A variation of the NGCC is the natural gas combined heat and power cycle (NGHPC). In such plants, the waste heat recovered from the turbine exhaust gas is not used to produce steam for electricity generation; instead, it is used to supply heat to an adjacent facility, such as a refinery. The end result is a plant that produces both electricity and useful heat. NGHPC plants have even higher overall energy efficiencies than NGCC plants, at lower capital costs, due to the elimination of the steam cycle. Several NGHCC systems are being used in oil, gas and petrochemical industries across Canada.

3.0 PCC, IGCC and NGCC: Environmental and Economic Performance

Table 1 highlights key performance standards for current/future PCC and IGCC, current IGCC demonstration plants, and current NGCC. The cost and performance data for IGCC are updated from the original 2001 combustion technologies assessment and include up-to-date information and the actual performance of the operating Wabash River and Polk IGCC plants.

Table 1: Comparison of Present and Projected Environmental Performance and Economic Costs of PCC, IGCC and NGCC

	Present[7]		2010–2015[7]		2015–2025[7]		Wabash IGCC	Polk IGCC	NGCC
	PCC	IGCC	PC	IGCC	PC	IGCC			
Capital Cost (US$/kW)	1,000–1,200	1,200–1,500	900–1,100	1,000–1,200	900–1,000	800–1,000	1,672[8]	1,650[9]	450[10]
Efficiency (% HHV)	40–43	40–44	45–50	45–50	50–53	50–60	~39[8]	35.4[9]	50.2[12]–53.4[11]

7 PC and IGCC 'Present'denotes "best available technology" estimates by CANMET. Data values for 2010–2015 and 2015–2025 are estimates of future performance. CANMET Energy Technology Centre, *Canada's Clean Coal Technology Roadmap,* (Ottawa: Natural Resources Canada, 2005), www.nrcan.gc.ca/es/etb/cetc/combustion/cctrm/pdfs/cctrm_e_(lowres).pdf

8 John N. O'Brien, Joel Blau and Matthew Rose, *An Analysis of the Institutional Challenges to Commercialization and Deployment of IGCC Technology in the U.S. Electric Industry: Recommended Policy, Regulatory, Executive and Legislative Initiatives Final Report* (Washington, DC: U.S. Department of Energy, National Energy Technology Laboratories, Gasification Technologies Program, National Association of Regulatory Utility Commissioners, 2004), www.netl.doe.gov/energy-analyses/pubs/FinalReport2-20Vol1.pdf

9 U.S. Department of Energy, *Tampa Electric Polk Power Station Integrated Gasification Combined Cycle Project — Final Technical Report,* (Washington, DC: U.S. DOE, 2002).

10 Timothy L. Johnson and David W. Keith, "Fossil Electricity and CO_2 Sequestration: How Natural Gas Prices, Initial Conditions and Retrofits Determine the Cost of Controlling CO_2 Emissions," *Energy Policy* 32, no. 3 (2002).

11 U.S. Department of Energy, Office of Fossil Energy, *Market-Based Advanced Coal Power Systems Final Report May 1999,* (Washington, DC: 1999), www.netl.doe.gov/technologies/coalpower/refshelf/marketbased_systems_report.pdf

	Present[7]		2010–2015[7]		2015–2025[7]		Wabash IGCC	Polk IGCC	NGCC
	PCC	IGCC	PC	IGCC	PC	IGCC			
CO_2 Emission Rate without Capture (kg/MWh)	722–941[12]	682–846[12]	-		-		CO2 Reduced by 20%[13]	-	344–364[12]
CO_2 Emission Rate with capture (kg/MWh)	59–148[12]	70–152[12]	-		-		-	-	40-63[12]
SO_2 — Coal Specific (ng/J)	198–1,462	43	4.5–5	4.5–5	<1 Matching to NGCC		51.6[14]	64.5[14]	0–0.7[15]
NO_x (ng/J)	219–258	64	4–5		<4		64.5[14]	116.2[14]	5[15]
Mercury Removal (%)	n/a	50	70–90		>90		0.0019 (ng/J)[14]	0.0022 (ng/J)[14]	0[15]
PM_{10} and $PM_{2.5}$ (ng/J)	15–30	5	2–3		<2		5.2[14]	6.5[14]	2[15]
VOCs (mg/Nm^3 flue gas)		1/150 of permitted	1		<1		11.3 (ng/J)[16]	-	1[15]
Efficiency De-rating for 90% CO_2 Removal (%HHV)	7–12	6–8	4–7	4–5	2–4	2–3	-	-	7.4[12]
Capital Cost for CO_2 Removal (US$/kW)	700–900	300–800	500–600	200–500	300–400	100–300	-	-	373–1330[12]

[12] Edward S. Rubin, Anand B. Rao and Chao Chen, "Comparative Assessments of Fossil Fuel Power Plants With CO_2 Capture and Storage," *Proceedings of 7th International Conference on Greenhouse Gas Control Technologies (GHGT-7),* Vancouver, Canada, September 5–9, 2004, Vol. I: Peer-Reviewed Papers and Overviews, p.285.293, www.iecm-online.com/PDF%20Files/2004e.%20Rubin%20et%20al,%20GHGT-7%20Sept.pdf

[13] As Wabash River was a repowering project, the 20% decrease in CO_2 emissions is with respect to previous operation as a conventional coal plant. U.S. Department of Energy, National Energy Technology Laboratory, *Wabash River Coal Gasification Repowering Project: A DOE Assessment* (Washington, DC: U.S. DOE, 2002), www.fischer-tropsch.org/DOE/DOE_reports/Wabash%20River%20Repowering/2002/2002-1164/2002-1164%20-%20DOE%20ASSMNT.pdf.

[14] Jay A. Ratafia-Brown, Lynn M. Manfredo, Jeff W. Hoffmann, Massood Ramezan and Gary J. Stiegel, "An Environmental Assessment of IGCC Power System" (paper presented at the Nineteenth Annual Pittsburgh Coal Conference, September 23–27, 2002).

[15] Canadian Clean Power Coalition Analysis (Date Unknown). Accessed online at www.nrcan.gc.ca/es/etb/cetc/combustion/co2trm/pdfs/ccpc_coal_plant_modifications.pdf.

[16] P. Amick and R. Dowd, "Environmental Performance of IGCC Repowering for Conventional Coal Power Plants" (paper presented at the Gasification Technologies Conference, San Francisco, California, October 9, 2001).

	Present[7]		2010–2015[7]		2015–2025[7]		Wabash IGCC	Polk IGCC	NGCC
	PCC	IGCC	PC	IGCC	PC	IGCC			
COE without Capture (US cents/kWh)	3.5–4.4	4.4–4.9	3.0–4.1	3.0–4.1	<3.0	<3.0	-	5.9 (2004)[17]	2.2–3.5[12]
COE with CO_2 Capture (US cents/kWh)	6.3–7.9	5.7–6.4	3.6–4.9	3.3–4.5	-	-	-	-	3.2–5.8[12]

"-": no data provided.

3.1 Environmental Performance

A review of the available information indicates that IGCC and NGCC outperform all other coal combustion technologies for environmental performance, including PCC. Further, NGCC strongly outperforms coal combustion in every emissions category, while the same is true for IGCC vis-à-vis PCC. It should also be noted that NGCC's environmental performance today still outperforms (or is comparable) to future projections for PCC and IGCC out to 2025.

Specifically, when compared to IGCC (and in the absence of carbon capture on either process) NGCC emits

- ~1/2 the CO_2 (344–364 kg/MWh versus 682–846 kg/MWh)
- ~0 SO_2 emissions (0–0.7 ng/J versus 43 ng/J)
- <1/12 the NOx emissions (5 ng/J versus 64 ng/J)
- 0 mercury emissions (0 versus 50% removal)
- <1/2 the PM emissions (2 ng/J versus 5 ng/J)

Meanwhile, IGCC clearly outperforms PCC (also in the absence of carbon capture) by emitting

- slightly less CO_2 (682–846 kg/MWh versus 722–941 kg/MWh)
- <1/4 of the SO_2 emissions (43 ng/J versus 198–1,462 ng/J)
- <1/12 the NOx emissions (64 ng/J versus 219–258 ng/J)
- <1/3 the PM emissions (5 ng/J versus 15–30 ng/J)

IGCC offers the additional advantage of cheaper and easier carbon capture and storage (CCS) possibilities over PCC and NGCC. As such, proponents of IGCC often mention CCS as a viable add-on to the technology, with some observers[18] having gone so far as to analyze varying degrees of IGCC-based capture for technical and economic performance. In light of such

[17] U.S. Department of Energy, Office of Fossil Fuel, National Energy Technology Laboratory, *Clean Coal Technology: Tampa Electric Integrated Gasification Combined-Cycle Project: A DOE Assessment* (Washington, DC: U.S. DOE, 2004), www.netl.doe.gov/technologies/coalpower/cctc/cctdp/bibliography/demonstration/pdfs/tampa/TampaPPA8%20Final080904.pdf.

[18] Guillermo Ordorica-Garcia, Peter Douglas, Eric Croiset and Ligang Zheng, "Technoeconomic Evaluation of IGCC Power Plants for CO_2 Avoidance," *Energy Conversion and Management* 47, no.15-16 (2006), 2250–2259.

speculative discussions in the Ontario context, this report examines the potential for CCS in Ontario (section 5).

3.2 Capital Costs

NGCC outperforms all coal combustion technologies in terms of capital cost. Table 1, above, illustrates this outperformance relative to both PC and IGCC at current and even future projections out to 2025. The capital costs of both coal combustion options exceed that of NGCC by more than 200%. In fact, the high capital cost of IGCC has impeded its economic attractiveness.

Current capital costs estimates for the three technologies are shown in Table 2.

Table 2: Capital Costs of NGCC, IGCC and PC

Generating Technology	Cost (US$/kW)
NGCC	450
IGCC	1,200–1,500
PC	1,000–1,200

As shown in Table 3, the incremental capital cost of adding CO_2 capture is lower for IGCC than for either NGCC or PC.

Table 3: Incremental Capital Costs of Adding CO_2 Capture to IGCC, NGCC and PC

Technology	Additional Capital Cost of CO_2 Capture (US$/kW)
NGCC	373–1,330
IGCC	300–800
PC	700–900

In the future companies will likely be expected to include measures or offsets to reduce GHG emissions.

3.3 Operating Costs — Fuel

The key weakness of NGCC power systems is the volatility of feedstock (natural gas) prices. While natural gas may serve as an ideal bridging fuel to a sustainable future, questions remain over whether an adequate supply is available to meet Ontario's increase in demand for natural gas that could result from a phase out of coal and nuclear power.[19] Further questions remain over whether natural gas as an input will be available at a level and stability of price that would keep NGCC generation cost competitive relative to electricity production from other fuel sources, such as coal. The high level of volatility in natural gas prices has been a "concern to investors

[19] For a discussion of the potential role of natural gas as a transitional fuel in Ontario see Winfield, Horne, McCleneghan and Peters, *Power for the Future.*

and developers of natural gas-fired facilities"[20] with the price of natural gas fluctuating by as much as $8 Cdn per gigajoule in a calendar year.

A review of projected future North American natural gas prices, gathered from a variety of projections from government, industry and industry observer sources, is presented in Table 4.

Table 4: Projected North American Natural Gas Prices 2005–2025

Source (Price Point)	Units	2005	2010	2015	2020	2025	Trend (2005-2025)
Canadian Market							
NEB (Industrial use) Supply Push scenario[21]	1986Cdn$/GJ	5.00	5.40	5.10	4.90	4.75	5% decrease
NEB (Industrial use) Techno-vert[22]	1986Cdn$/GJ	4.90	4.85	4.60	4.40	4.25	13 % decrease
NRCan (AECO-C)[23]	Cdn$/GJ			6.25		6.75	8% increase
Power for the Future (AECO-C)	Cdn$/GJ	4.50	4.70	5.00	4.30	4.90	9% increase
American Market							
Sproule (Henry Hub)	US$/mmbtu	7.34	6.14	6.62	7.12	7.67	4% increase
NRCan (NYMEX)[24]	US$/mmbtu			5.55		6.25	13% increase
Energy Information Assoc. (Lower 48 wellhead)	2003US$/mcf	5.30	3.64	4.16	4.53	4.79	10% decrease
Global Insight	2003US$/mcf			3.84		3.96	3% increase
Energy Ventures Analysis	2003US$/mcf			3.71		3.98	7% increase
DB	2003US$/mcf			3.66		3.66	No change
Strategic Energy and Economic Research	2003US$/mcf			3.9		4.26	9% increase
Altos	2003US$/mcf			3.92		5.78	47% increase

The data provided in Table 4 were used to calculate simple averages, shown in Table 5.[25]

[20] National Energy Board, *Canada's Conventional Natural Gas Resources: A Status Report* (Calgary: NEB, 2004), 13, www.neb-one.gc.ca/energy/EnergyReports/CanadaConventionalNGResources2004/CanadaConventionalNGResources2004_e.pdf.

[21] National Energy Board, *Canada's Energy Future: Scenarios for Supply and Demand to 2025* (Calgary: NEB, 2003), www.neb.gc.ca/energy/SupplyDemand/2003/SupplyDemand2003_e.pdf.

[22] National Energy Board, *Canada's Energy Future.*

[23] Natural Resources Canada, *Natural Gas Review of 2004 & Outlook to 2020: Executive Summary,* (Ottawa: NRCAN, Natural Gas Division Petroleum Producers Branch, Energy Policy Sector, 2005), www2.nrcan.gc.ca/es/erb/CMFiles/Executive_Summary_English_2005209PVS-30112005-9179.pdf.

[24] Natural Resources Canada, *Natural Gas Review of 2004 & Outlook to 2020.*

Table 5: Aggregated Natural Gas Projected Price Changes 2005-2025

Average of all positive and negative 2025 changes (%)	13.4
Average of all positive increases only (%)	21.0
Average of positive increases (without Altos 47% outlier) (%)	11.7

In summary, the available long-term projections of natural gas prices, a key factor in the operating costs of NGCC, suggest only moderate increases in price out to 2025. Studies completed by Professor Peter Douglas at the University of Waterloo suggest that NGCC is the preferred option for achieving reductions of electricity-related CO_2 emissions in Ontario within these projected price ranges.[26]

3.4 Summary of Key Findings

The key findings of this section are as follows:

- NGCC outperforms all coal-based options in all categories of emissions now and into the foreseeable future.
- Among the coal-based options, IGCC outperforms all other options in all categories of emissions now and into the foreseeable future.
- NGCC outperforms IGCC and PCC in terms of capital costs (100–200%) if there are no requirements to offset or capture CO2 emissions.
- The incremental costs of adding carbon capture to IGCC are lower than with all other generating options, although IGCC with carbon capture has yet to be put into practice.
- Long-term projections of natural gas prices, a key factor in the operating costs of NGCC, suggest only moderate increases in price out to 2025.

[25] Where price forecasts dated 2005 were not listed, an extrapolated point was generated by doubling the percentage increase from 2015 to 2025 to account for the time between 2005 and 2015 assuming that the trend of percentage increase can be extrapolated back to 2005. Then the aggregate percentage increase was taken as 2005 to 2025 for all data points.

[26] P.L. Douglas, "CO_2 Capture and Geological Storage in Ontario" (paper presented at the CO_2 Capture and Geological Storage in Ontario Workshop, Toronto, February 16, 2006).

4.0 IGCC Commercialization

4.1 Plants Currently in Operation in North America

IGCC is still a rarely used technology for coal combustion-based electricity generation. As of 2004 there were only a few IGCC commercially sized electricity generation plants operating worldwide; two of these are in North America (both in the United States).[27] Of note, only one has a dedicated coal fuel stream. The existing plant locations, their generating capacity, fuel stream, and the year completed are as follows:

- Wabash River, USA, 262 MW, coal and/or coke, 2001
- Polk, Tampa, USA, 250 MW, coal and/or coke, 2001
- Buggenum, Netherlands, 253 MW, coal, 2000
- Shell Pernis Netherlands, 120 MW, cogeneration, refinery bottoms
- Elcogas, Puertollano, Spain, 298 MW, 50:50 coal:petroleum coke, 1998
- Sarlux, Italy, 551 MW, petroleum coke
- Negishi, Japan, 342 MW, asphalt, 2003

The IGCC plants in Wabash River and Polk are demonstration projects to which the U.S. Department of Energy (DOE) provided a 50% capital cost subsidy. Details on their costs and performance are outlined here:

- Wabash River, a re-powered plant, started production in November 1995 with a total capital cost of US $438 million, of which US $219M (or 50%) was provided by the DOE.[28] Plant efficiency[29] is 37.8–40.2%. The project initially encountered environmental problems, such as the presence of arsenic, selenium, and cyanide in wastewater streams, and SO_2 and NOx emissions exceeding *Clean Air Act* requirements.[30]
- The Polk plant, the first U.S. greenfield IGCC plant,[31] started production in September 1996 with a total project cost of US $303.3 million, of which US $151M (49%) was provided by the DOE. Emissions of sulphur oxides, nitrogen oxides, and particulates are well below regulatory limits, with an efficiency of 35.4% HHV, though this is slightly lower than the design efficiency of 38.6%.[32]

A third plant, Pinon Pine (107 MW, fluidized bed gasifier, 1998) failed to operate successfully.

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27 Ontario Power Authority, *Supply Mix Advice and Recommendations Report,* (2005), www.powerauthority.on.ca/Report_Static/1139.htm

28 U.S. Department of Energy, National Energy Technology Laboratory, *Wabash River Coal Gasification Repowering Project*.

29 Where efficiency describes how much energy in the fuel is converted into electrical energy.

30 U.S. Department of Energy, National Energy Technology Laboratory, *Wabash River Coal Gasification Repowering Project.*

31 U.S. Department of Energy, *Pioneering Gasification Plants,* www.fe.doe.gov/programs/powersystems/gasification/gasificationpioneer.html

32 U.S. Department of Energy, Office of Fossil Fuel, National Energy Technology Laboratory, *Clean Coal Technology: Tampa Electric Integrated Gasification Combined-Cycle Project.*

Despite a total project cost of US $335.9 million, of which US $167.9M (50%) was provided by the DOE, equipment problems with the filter-fines removal system and the gasifier resulted in discontinuation of the plant startup in 2001.[33]

4.2 Proposed Plants in North America

Despite the mixed performance and reliance on subsidization amongst the U.S. IGCC plants, many more such plants are planned. Currently, there are 140 proposed coal plants in the U.S, promising a total of 85 GW of power at an investment of US $119 billion. The addition of this power capability is roughly equal to the power needed to supply 85 million homes.[34] Of the 140 coal power plants proposed, 14 are slated to be IGCC plants, with one that will incorporate CCS. Nine of the 14 are scheduled to be completed by 2012.

The 14 proposed plants are listed below:

- FutureGen, 275 MW, location still to be determined. A ten-year, US $1 billion project integrating IGCC with CCS, with the power industry contributing 20% of the capital costs.[35] Scheduled to be in service by 2012.[36]
- Global Energy, 600 MW, Lima, Ohio. Scheduled to be in service by 2008.
- Excelsior Energy — Mesaba, 531 MW, near Hibbing, Minnesota. Scheduled to be in service by 2010. The DOE will provide US $36 million (1.8%) toward the US $1.97 billion cost.[37]
- Orlando Utilities Commission, 285 MW, Orange County, Florida. Scheduled to be in service by 2010.[38] The DOE will contribute US $235 million (42%) of the estimated US $557 million total cost.[39]
- American Electric Power, 600 MW, Meigs County, Ohio. Scheduled to be in service by 2010.[40]
- The ERORA Group, 770 MW, near Taylorville, Illinois.[41] The DOE will provide US $60 million (14.5%) in funding support for the US $414 million total cost.[42] Scheduled to be in service by 2010.[43]

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[33] U.S. Department of Energy, National Energy Technology Laboratory, *Piñon Pine IGCC Power Project: A DOE Assessment,* (Washington, DC: DOE, 2002), www.osti.gov/bridge/servlets/purl/805670-S8pCpG/native/805670.pdf.

[34] U.S. Department of Energy, National Energy Technology Laboratory, *Tracking New Coal-Fired Power Plants: Coal's Resurgence in Electric Power Generation,* (Washington, DC: DOE, 2006), www.netl.doe.gov/coal/refshelf/ncp.pdf

[35] U.S. Department of Energy, National Energy Technology Laboratory, "Abraham Announces Pollution-Free Power Plant of the Future: $1 Billion 'Living Prototype' to Showcase Cutting-Edge Technologies to Advance President's Climate Change, Hydrogen Initiatives," news release, February 27, 2003.

[36] FutureGen Alliance, "Timeline," www.futuregenalliance.org/about/timeline.stm.

[37] U.S. Department of Energy, Office of Fossil Energy, National Energy Technology Laboratory, *Project Fact Sheet - Mesaba Energy Project* (Washington, DC: DOE, 2005), www.netl.doe.gov/publications/factsheets/project/Proj342.pdf

[38] U.S. Department of Energy, National Energy Technology Laboratory, *Tracking New Coal-Fired Power Plants*.

[39] U.S. Department of Energy, National Energy Technology Laboratory, "Secretary Abraham Announces $235 Million for Florida Clean Coal Plant," news release, October 21, 2004.

[40] U.S. Department of Energy, National Energy Technology Laboratory , *Tracking New Coal-Fired Power Plants*.

[41] GEEnergy, "GE Gasification Technology Licensed For Proposed IGCC Plant In Illinois," news release, January 23, 2006.

[42] U.S. Department of Energy, "Kentucky Pioneer IGCC Demonstration Project: Final Environmental Impact Statement," accessed at www.eh.doe.gov/NEPA/eis/EIS0318/eis/Chapter_3.pdf.

[43] U.S. Department of Energy, National Energy Technology Laboratory, *Tracking New Coal-Fired Power Plants*.

- Southeast Idaho Energy LLC, 500 MW, Pocatello, Idaho. Scheduled to be in service by 2010.[44]
- Energy Northwest, 600 MW, Kalama, Washington. Scheduled to be in service by 2012.[45]
- American Electric Power (Appalachian Power), 600 MW, Mason County, West Virginia. Scheduled to be in service by 2012.[46]
- Tondu Corp., 630 MW, St. Joseph County, Indiana. Startup date has not yet been determined.[47]
- Steelhead Energy Company, 545 MW, Williamson County, Illinois. Startup date has not yet been determined.[48]
- Duke/Cinergy (operating under PSI Energy), 600 MW, Edwardsport, Indiana.[49] Startup date has not yet been determined.[50]
- CME International, 600 MW, Hanging Rock, Ohio. Startup date has not yet been determined.[51]
- First Energy/Consol. Capacity, location and startup date all yet to be determined.[52]

The Global Kentucky Pioneer Energy project (540 MW), scheduled to start up in 2004 in Clark County, Kentucky,[53] was cancelled due to permitting issues, financing, and the loss of their power-purchase agreement.[54] The DOE has provided US $78 million in cost shared funding support of the estimated US $432 million project cost.[55]

4.3 Barriers to Commercialization of IGCC

Despite the expansion of IGCC projects in the U.S., such projects have not proceeded without funding from the U.S. DOE; the technology is thus considered by some to still be commercially unproven. IGCC plants account for only 14 of 140 proposed new coal plants in the U.S. and none in Canada.

The National Association of Regulatory Utility Commissioners (NARUC) completed a detailed, comprehensive survey analyzing the barriers impeding IGCC commercialization in the U.S. The survey consisted of 48 participants who were experts and/or institutional stakeholders representing energy companies, technology-engineering companies, government organizations, and consulting companies.[56]

One of the key barriers identified was financial,[57] including high capital costs, reliance on government subsidies and high front-end engineering costs. Other observers noted political

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44 U.S. Department of Energy, National Energy Technology Laboratory, *Tracking New Coal-Fired Power Plants*.
45 U.S. Department of Energy, National Energy Technology Laboratory, *Tracking New Coal-Fired Power Plants*.
46 U.S. Department of Energy, National Energy Technology Laboratory, *Tracking New Coal-Fired Power Plants*.
47 U.S. Department of Energy, National Energy Technology Laboratory, *Tracking New Coal-Fired Power Plants*.
48 U.S. Department of Energy, National Energy Technology Laboratory, *Tracking New Coal-Fired Power Plants*.
49 Cinergy Corp, Cinergy/PSI, and GE, "Bechtel to Explore Building Cleaner Coal Power Plant," news release, October 26, 2004.
50 U.S. Department of Energy, National Energy Technology Laboratory, *Tracking New Coal-Fired Power Plants*.
51 U.S. Department of Energy, National Energy Technology Laboratory, *Tracking New Coal-Fired Power Plants*.
52 U.S. Department of Energy, National Energy Technology Laboratory, *Tracking New Coal-Fired Power Plants*.
53 U.S. Department of Energy, National Energy Technology Laboratory, *Tracking New Coal-Fired Power Plants*.
54 Gary Stiegel (National Energy Technology Laboratory), in discussion with author, 2006.
55 U.S. Department of Energy, "Project Fact Sheet: Kentucky Pioneer Energy IGCC Demonstration Project," fact sheet, 2003, www.netl.doe.gov/technologies/coalpower/cctc/cctdp/project_briefs/clnen/documents/clnen.pdf
56 O'Brien, Blau and Rose, *An Analysis of the Institutional Challenges*.
57 The fourth top barrier offered by respondents was the risk of low plant availability.

barriers, such as a lack of public and political demand for IGCC-based plants. In Canada in particular these barriers included the political uncertainty around Canadian federal government changes to Canada's climate change strategy and its participation in the Kyoto Protocol, and the corresponding uncertainty of emissions reduction-based tax credits and favourable environmental regulations.[58]

Finally, the NARUC study listed two technology barriers: the risk of low plant availability in the early stages of operation (existing IGCC plants have had varying rates of availability) and the poor initial performance records of the Wabash River and Pinon Pine plants. These risks are aggravated by a lack of performance guarantees from a single vendor, as IGCC projects are normally constructed through a mosaic of vendors and service providers.

In a future context of CO_2 emissions pricing as a result of, for example, "cap-and-trade" regulations, the economic attractiveness of IGCC may improve. The Pembina Institute has constructed a range of plausible future scenarios of CO_2 emissions pricing for new large industrial facilities in Canada. Under these scenarios, the financial liability from emissions pricing results in an additional cost for an illustrative coal-fired electricity generation facility of about 1 to 5¢/kWh in 2025 and about 5 to 15¢/kWh in 2050.[59] When building a new generating plant, these escalating future financial liabilities may make using either IGCC or IGCC with carbon capture economically preferable to conventional coal-fired technologies.

4.4 Summary of Key Findings

The key findings of this section are as follows:

- IGCC is still a rarely used technology for coal combustion-based electricity generation, with only one plant using dedicated coal as a fuel source, and two others using a coal and coke mix. There are no IGCC plants yet operating in Canada.
- Two IGCC plants are currently in operation in North America, both in the U.S.: Wabash River and Polk. Approximately half their capital costs were covered by the U.S. DOE.
- Fourteen IGCC-based plants are currently being proposed in the U.S., one of which will feature CCS.
- There are still financial and technological barriers to IGCC commercialization, particularly the high capital costs associated with the technology. The financial attractiveness of the technology would be improved by the pricing of CO_2 emissions, as is likely to occur in the near future.

[58] Manfred Klein (Electricity and Industrial Combustion Division), in discussion with author, April 20, 2006.
[59] Matthew Bramley, *Financial Liability for Greenhouse Gas Emissions from Large Industrial Facilities in Canada,* (Ottawa, ON: The Pembina Institute, 2005), 35, www.pembina.org/pdf/publications/Liability05_final.pdf.

5.0 Carbon Capture and Storage Options for Ontario

One of the features of IGCC technology is that, in theory, it is more feasible to capture the CO_2, the most important of the long-lived GHGs, from the operation of IGCC facilities than from other fossil fuel-fired technologies. This opens the possibility that GHG emissions from the IGCC facilities might be captured and stored or sequestered, rather than released into the environment.

The Pembina Institute's earlier work on carbon capture and storage (CCS) focussed on the possibilities of applying this technology in western Canada.[60] This section explores the possibilities for applying CCS in an Ontario context.

To geologically store CO_2, the storage locations must meet several requirements, as outlined by Stefan Bachu of the Alberta Geological Survey:[61]

- Adequate space to store large volumes of CO_2 emissions
- Injectivity of the formation to accept CO_2 at efficient delivery rates
- Confining ability of the formation to prevent leakage and migration
- Adequate depth (>1000 m)
- Minimally faulted, fractured, folded
- Ability to avoid contamination of energy, mineral, and groundwater resources
- Ability to avoid risk to life (plants, animals, humans)
- Ability to minimize leakage for the desired time period.

Many of these criteria can be met in some areas of Alberta, but are less likely to be met in Ontario. The geology of the Canadian Shield, which constitutes the bulk of northern Ontario, is inappropriate for CCS. Furthermore, preliminary work completed by the Alberta Research Council for Natural Resources Canada concluded that the sedimentary strata of southwestern Ontario and southern Quebec were considered the lowest priority in terms of their potential for CCS. The Western Canada Sedimentary Basin, and basins in Nova Scotia and Manitoba, were identified as more likely candidates.[62]

Other important factors to include are site accessibility, surface infrastructure, distance to CO_2 source (to minimize transportation costs), surface/subsurface/social conflicts, avoidance of emissions penalties and low seismic risk.[63]

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[60] Griffiths, Cobb and Marr-Laing, *Carbon Capture and Storage.*

[61] Stefan Bachu, "Site Selection for CO_2 Capture and Geological Storage (CCGS)," Alberta Geological Survey and Alberta Energy and Utilities Board, www.nrcan.gc.ca/es/etb/cetc/combustion/co2trm/pdfs/ontario_ccs_bachu.pdf (accessed October 2006).

[62] Stefan Bachu, "Evaluation of Sedimentary Basins in Canada for CO_2 Storage: A Proposed Role for the Federal and Provincial Geological Surveys," Appendix A in Bill Guntet and Rick Chalatumyk, *The CANiSTORE Program: Planning Options for Technology and Knowledge Base Development for the Implementation of Geological Storage, Development and Deployment in Canada* (Edmonton: Alberta Research Council, 2004), www.nrcan.gc.ca/es/etb/cetc/combustion/co2trm/pdfs/canistore_final_report.pdf.

[63] Stefan Bachu, "Site Selection for CO_2 Capture and Geological Storage (CCGS)."

Two methods of current commercial carbon sequestration are injection into oil and gas wells, and into deep saline aquifers. While deep coal seams are another sequestration option at other locations, no deep coal seams exist in Ontario.[64]

5.1 Oil and Gas Wells

Since 1858, southern Ontario has seen a cumulative production of 1.3 Tcf natural gas from 262 gas pools and 85 million barrels of oil from 137 oil pools, producing 6,502 abandoned wells. While depleted oil and gas reservoirs may offer an opportunity to sequester and store CO_2, the possible issues associated with CO_2 storage in hydrocarbon reservoirs include unplugged wells, small pool sizes, and shallow depths.[65] As such, a substantial amount of historical and technological research would be required to determine whether CO_2 storage in depleted oil and gas reservoirs is a viable option in Ontario.

The current condition of Ontario's oil and gas reservoirs is not well documented[66] nor have long-term storage issues been explored.[67] Wells in Ontario have been abandoned anywhere between 20–90 years, requiring testing to determine the quality, quantity, and strength of existing cement plugging. The possibility of CO_2 reacting with the cement plugging (thereby resulting in leakage) requires investigation as well.[68] For oil and gas reservoir sequestration to occur, these wells must be investigated in detail to determine their status, their ability to prevent leaks under sequestration pressure, and the impact that would result should a failure occur.[69]

The situation is further complicated by seismic instability in southern Ontario. It has been suggested that a magnitude 7 earthquake could occur, on average, once every 3,000 years in the region.[70]

Other information required to determine the possibility of CO_2 sequestration in hydrocarbon reservoirs in Ontario would include[71]

- the location of unmapped faults and fractures
- the presence of undiscovered hydrocarbons
- the possibility of abandoned well cap corrosion by CO_2
- the porosity, permeability, migration pathways and migration distance of potential reservoir locations
- reservoir temperature
- sweep efficiency and potential geochemical reactions.

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[64] Terry Carter and Sarah O'Connor-Hames, "Geological Opportunities for Carbon Sequestration in Ontario" (paper presented at Carbon Dioxide Capture and Geological Storage (CGS): An Opportunity for Sustainable Energy Development in Ontario Workshop, Toronto, Ontario, February 16, 2006).
[65] Carter and O'Connor-Hames, "Geological Opportunities for Carbon Sequestration in Ontario."
[66] Ahmed Shafeen, E. Croiset, P.L. Douglas, J. Chatzis and B. Seckington, "Techno-Economic Assessment of Geological CO_2 Sequestration in Ontario," (paper presented at the 7th International Conference on Greenhouse Gas Control Technologies (GHGT-7), Vancouver, Canada, September 5–9, 2004).
[67] Carter and O'Connor-Hames, "Geological Opportunities for Carbon Sequestration in Ontario."
[68] Shafeen, Croiset, Douglas, Chatzis and Seckington, "Techno-Economic Assessment of Geological CO_2 Sequestration in Ontario."
[69] Shafeen, Croiset, Douglas, Chatzis and Seckington, "Techno-Economic Assessment of Geological CO_2 Sequestration in Ontario."
[70] Charles C. Plummer, *Physical Geology and the Environment*, (Toronto, ON: McGraw Hill Ryerson, 2004).
[71] Ahmed Shafeen, "CO_2 Sequestration Opportunities for Ontario," Natural Resources Canada, CANMET Energy Technology Centre, www.nrcan.gc.ca/es/etb/cetc/combustion/co2trm/pdfs/sequest_ontario_feb2006.pdf.

Gathering this information would itself be a major technical and scientific undertaking.

5.2 Saline Aquifers

A saline aquifer is underground porous rock filled with salty or saline water.[72] For the purpose of carbon sequestration, CO_2 is pumped into the pore spaces displacing the salty water. The CO_2 rises to the top of the aquifer and, over tens to hundreds of years, eventually dissolves into the salty water, reacting with minerals in the formation to form stable compounds similar to carbonate.[73] One example of commercially operated saline aquifer sequestration is the Sleipner Project operated by Statoil in the North Sea off the coast of Norway, where CO_2 is compressed and pumped into a 200 m thick sandstone layer located 1,000 m below the sea floor. Approximately one million tonnes of CO_2 have been sequestered annually since 1996.[74]

Saline aquifers have been identified as the preferred option for CO_2 sequestration in Ontario by the CANMET Energy Technology Centre. The saline aquifers identified in Ontario are 800 m below the surface and contain suitable cap rock for CO_2 to be sequestered under supercritical conditions.[75] Still, risks associated with saline aquifer sequestration include migration, leakage to atmosphere and seismic hazards. Saline aquifers require cap rock to prevent the vertical leaks of CO_2 back up to the surface and horizontal migration.

Despite the availability of aquifers, the CANMET researchers acknowledge that it will be difficult to get public support for CCS in southwestern Ontario because of the population density of the surrounding areas, safety concerns around blowouts, environmental concerns related to Lake Erie, proximity to the U.S. border and the necessity of state-of-the-art monitoring.[76] The seismically active nature of the region would add further complications.

In addition there is emerging evidence that CO_2 sequestered in saline aquifers changes the acidity of the brine, causing carbonates in the rock to dissolve rapidly. Naturally occurring minerals that had previously sealed the pores and fractures in the rock would then be able to leak CO_2 and fouled brine.[77]

Before CCS in Ontario saline aquifers can be considered a viable option, further studies will be required. These would include[78]

- reservoir characterization (drilling experimental wells, identifying formation water chemistry, identifying formation water hydrodynamics, determining sweep efficiency, identifying fault characteristics)
- reservoir modeling
- evaluation of pipeline routes
- evaluation of seismic activity induced by deep well injection

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[72] Carter and O'Connor-Hames, "Geological Opportunities for Carbon Sequestration in Ontario."
[73] Howard J. Herzog, "What Future for Carbon Capture and Sequestration?," *Environmental Science & Technology* 35, no. 77 (2001), 148A–153A. http://sequestration.mit.edu/pdf/EST_web_article.pdf .
[74] Herzog, "What Future for Carbon Capture and Sequestration?"
[75] Shafeen, Croiset, Douglas, Chatzis and Seckington, "Techno-Economic Assessment of Geological CO_2 Sequestration in Ontario."
[76] Shafeen, Croiset, Douglas, Chatzis and Seckington, "Techno-Economic Assessment of Geological CO_2 Sequestration in Ontario."
[77] Wendy Frew, "Buried Gases May Escape: Scientists," *The Sydney Morning Herald* (Australia), July 5, 2006.
[78] Shafeen, "CO_2 Sequestration Opportunities for Ontario."

- evaluation of caprock integrity
- determination of abandoned well status
- investigation of legal issues, including coordination with affected U.S. jurisdictions (e.g., Michigan, Pennsylvania, Ohio, New York)
- investigation of undiscovered hydrocarbons[79]
- testing of abandoned well integrity for CO_2 corrosion[80]
- more detailed evaluation of porosity and migration.[81]

These investigations would again be a major technical and scientific undertaking and may ultimately lead to the conclusion that CCS is not a viable option.

5.3 Economic Barriers

Even if CCS options were to be become feasible, it has been estimated that, for CCS to be used with IGCC, there must be a carbon tax or equivalent above US $90/ton and natural gas prices exceed a threshold of US $4-6/GJ.[82] Other studies have suggested that the IGCC and CCS technologies would become attractive at an avoided cost of CO_2 ranging from US $20–190/tonne.[83]

5.4 Summary of Key Findings

The key findings of this section are as follows:

- Two potential options for CCS have been identified in Ontario: storage in depleted oil and gas reservoirs, and sequestration in saline aquifers.
- The current condition of Ontario's oil and gas reservoirs is not well documented, and therefore their suitability for CCS is difficult to assess. Significant technical and scientific investigations would be required to establish their viability for storage.
- Saline aquifers have been identified as the preferred option for CO_2 sequestration in Ontario by one group of researchers. However, significant technical and scientific investigations would be required to establish the viability of this option.
- There is emerging evidence showing that the addition of CO_2 to saline aquifers can increase the acidity of the brine, with the potential to dissolve minerals in surrounding rock, thus

[79] Carter and O'Connor-Hames, *Geological Opportunities for Carbon Sequestration in Ontario*.
[80] Carter and O'Connor-Hames, *Geological Opportunities for Carbon Sequestration in Ontario*.
[81] Carter and O'Connor-Hames, *Geological Opportunities for Carbon Sequestration in Ontario*.
[82] T.G. Kreutz and R.H. Williams, "Competition Between Coal and Natural Gas in Producing H_2 and Electricity Under CO_2 Emission Constraints" (paper presented at the 7th International Conference on Greenhouse Gas Control Technologies, Vancouver, Canada).
[83] Intergovernmental Panel on Climate Change (IPCC), *Special Report: Carbon Dioxide Capture and Storage, Summary for Policymakers and Technical Summary*, (Geneva: IPCC, 2005), www.ipcc.ch/activity/srccs/.

raising the possibility of leaks of CO_2 and fouled brine.

- The potential for seismic activity in southern Ontario presents significant barriers to CCS options in the region.
- In addition to these technical challenges, CCS options in Ontario would face significant political, economic and social barriers.
- In light of these findings, CCS can only be considered speculative discussion in an Ontario context. It cannot be considered a serious possibility for the purposes of the province's current electricity policy planning horizon (i.e., 20 years).

6.0 Conclusions

This study updates previous studies on the environmental and economic performance of various coal- and natural gas-fired technologies for electricity generation and examines the viability of CCS as an option for dealing with GHG emissions arising from the use of these technologies for electricity generation. The key findings are as follows:

Combustion Technologies for Electricity Generation

- NGCC outperforms all coal-based options in all categories of emissions now and into the foreseeable future.
- Among the coal-based options, IGCC outperforms all other options in all categories of emissions now and into the foreseeable future.
- IGCC is still a rarely used technology for coal combustion-based electricity generation, with only two commercial-sized facilities operating in North America. There are no IGCC plants yet operating in Canada.
- NGCC outperforms IGCC and PCC in terms of capital costs (by 100–200%) if there are no requirements to offset or capture CO_2 emissions.
- The incremental costs of adding carbon capture to IGCC are lower than with all other generating options, although IGCC with carbon capture has yet to be put into practice. An IGCC facility with carbon capture is currently being proposed for North America.
- Full commercialization of IGCC faces financial and technological barriers, particularly the high capital costs associated with the technology. The financial attractiveness of the technology would be improved by the pricing of CO_2 emissions, as is likely to occur in the near future.
- Long-term projections of natural gas prices, a key factor in determining the operating costs of NGCC, suggest only moderate increases in price out to 2025.

Carbon Capture and Storage in Ontario

- Two potential options for CCS have been identified in Ontario: storage in depleted oil and gas reservoirs, and sequestration in saline aquifers.
- The current condition of Ontario's oil and gas reservoirs is not well documented, and therefore their suitability for CCS is difficult to assess. Significant technical and scientific investigations would be required to establish their viability for storage.
- Saline aquifers have been identified as the preferred option for CO2 sequestration in Ontario by one group of researchers. However, significant technical and scientific investigations would be required to establish the viability of this option.
- There is emerging evidence showing that the addition of CO_2 to saline aquifers can increase the acidity of the brine, with the potential to dissolve minerals in surrounding rock, thus raising the possibility of leaks of CO_2 and fouled brine.
- The potential for seismic activity in southern Ontario presents significant barriers to CCS options in the region.
- In addition to these technical challenges, CCS options in Ontario would face significant political, economic and social barriers.
- CCS can only be considered a speculative discussion in an Ontario context. It cannot be considered a serious possibility for the purposes of the province's current electricity policy planning horizon (i.e., 20 years).

Appendix 1: A Comparison of Combustion Technologies for Electricity Generation

(Pembina Institute: First Published October 2001)

The following tables compare coal combustion technologies. They summarize the characteristics of the various coal-fired generating technologies and compare them with cleaner burning natural gas systems. Footnotes and a glossary of abbreviations appear immediately following the tables. All dollars are Canadian currency unless otherwise noted.

Environmental Performance [i]

	Subcritical Pulverized Coal Combustion (PCC)	Supercritical PCC	Atmospheric Fluidized Bed Combustion	Pressurized Fluidized Bed Combustion	Integrated Gasification Combined Cycle	Natural Gas Combined Cycle	Natural Gas Combined Heat and Power Cycle
Plant Efficiency [ii]	33%	38-43%	36%	42% [iii]	45%	52%	~60%
Heat Rate (GJ/MWh)	10.9	9.5-8.4	10	8.6	8.0	6.9	6.0 per equiv. MWh
CO_2 (kg/MWh) [ii]	1000	870-770	920	790	735	400	350
Sulphur Removal Standard	Alberta: 180 ng/J U.S.: 260 ng/J, 70-90% removal and BACT [iv]						
SO_2 (kg/MWh) – no FGD	1.6 [v]	1.4 [vi]	0.3 [vii]	0.12 [iii]	~ zero	~ zero	~ zero
SO_2 (ng/J) – no FGD	229	221	30 [viii]	14	~ zero	~ zero	~ zero
S02 (ng/J) – with FGD	< 70	< 66	Not required	Not required	Not required	Not required	Not required
NO_x Removal Standard	Alberta: 125 ng/J U.S.: 65 ng/J						
NO_x (kg/MWh) – no SCR	2.1 [ii]	1.8 [vi]	0.5 [vii, viii]	<0.7	0.25-0.45 [ix] (w/ LNB)	0.12 (w/ LNB)	0.12 (w/ LNB)
NO_x (ng/J) – no SCR and w/ LNB	86-125 [v]	86-125 [v]	43	<86 [iii]	31-56	18 [x]	18 [x]
NO_x (ng/J) – with SCR and LNB	43-62	43-62	SCR not required	SCR probably not required	SCR probably not required	SCR probably not required	SCR probably not required
Particulate Matter Standard	Alberta: 13 ng/J U.S.: 13 ng/J						
PM (kg/MWh) – no ESP/Baghouse	0.5	0.4 [vi]	~0.4	Better than PCC but not as good as IGCC	~ zero	~ zero	~ zero
PM (ng/J) – no ESP/Baghouse	46	42	~42	Better than PCC but not as good as IGCC	~ zero	~ zero	~ zero
Mercury	Depends on coal source	Depends on coal source	Depends on coal source	Better than PCC but not as good as IGCC	Little or no air borne mercury	Little or no air borne mercury	Little or no air borne mercury

Pollution Control Add-ons

	Subcritical Pulverized Coal Combustion (PCC)	Supercritical PCC	Atmospheric Fluidized Bed Combustion	Pressurized Fluidized Bed Combustion	Integrated Gasification Combined Cycle	Natural Gas Combined Cycle	Natural Gas Combined Heat and Power Cycle
Flue Gas Desulphuriz-ation (FGD)	FGD required to meet most standards. Wet FGD can achieve >95% recovery, dry can achieve up to 70-80%.[xi]	FGD required to meet most standards. Wet FGD can achieve >95% recovery, dry can achieve up to 70-80%.[xi]	Not required	Not required	Not required	Not required	Not required
NO_x Control: Low NO_x Burners (LNB)	LNB can reduce approx. 50% NOx formation.	LNB can reduce approx. 50% NO_x formation.	May not be required due to low combustion temperature.	May not be required due to low combustion temperature and LNB on turbine.	Std equipment. Can achieve single digit ppm (better than 90%) NO_x in flue gas with LNB.	Std equipment. Can achieve single digit ppm (better than 90%) NO_x in flue gas with LNB.	Std equipment. Can achieve single digit ppm (better than 90%) NO_x in flue gas with LNB.
NO_x Control Selective Catalytic Reduction (SCR)	80% NO_x removal without ammonia slip problems. [xii]	80% NO_x removal without ammonia slip problems. [xii]	May not be required due to low combustion temperature.	May not be required due to low combustion temperature and LNB on turbine.	May not be required where LNBs are available to reduce NO_x by at least 90%.	May not be required where LNBs are available to reduce NO_x by at least 90%.	May not be required where LNBs are available to reduce NO_x by at least 90%.
	Note: Typically **both** LNB and SCR required in PCC plants to meet most standards.						
Baghouse or ESP	Requires bag house or ESP. Baghouse more efficient and less prone to upsets.	Requires bag house or ESP. Baghouse more efficient and less prone to upsets.	Requires bag house or ESP. Baghouse more efficient and less prone to upsets.	Requires bag house or ESP. Baghouse more efficient and less prone to upsets.	Not Required	Not Required	Not Required
Mercury[xiii]	With baghouse and FGD 60- 70% removal. ESPs not as effective.	With baghouse and FGD 60- 70% removal. ESPs not as effective.	With baghouse up to 70% removal.	With baghouse up to 70% removal.	Not Required	Not Required	Not Required
CO_2 Capture	From flue gas, difficult to recover.	From flue gas, difficult to recover.	From flue gas, difficult to recover.	Recovery should be similar to IGCC.	Relative to other options, recovery is more straightforward from off-gas. [xiv]	From flue gas, difficult to recover.	From flue gas, difficult to recover.

Operational Performance

	Subcritical Pulverized Coal Combustion (PCC)	Supercritical PCC	Atmospheric Fluidized Bed Combustion	Pressurized Fluidized Bed Combustion	Integrated Gasification Combined Cycle	Natural Gas Combined Cycle	Natural Gas Combined Heat and Power Cycle
Currently in use at:	Genesee 1& 2, Keephills, Wabamun. Many plants worldwide.	Europe, Japan, U.S. Many plants worldwide. (proposed for Genesee 3)	Pt. Aconi, NS uses Circulating Fluidized Bed (185 MW plant), first one in Canada 1993. [vii] Japan, Europe. Commonly used with high sulphur coal.	Sweden, Spain, U.S. 350 MW plant under construction in Japan. [xv] Commonly used with high sulphur coal.	General coal gasification well proven. IGCC used at three U.S. plants (Polk, Wabash,[xvi] Pinon Pine) and in The Netherlands and Spain.	Many plants worldwide.	Many plants worldwide.
Commercially Proven	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Scale	100-1000 MW	100-1000 MW	400 MW guaranteed by manufacturer. [viii]	80 MW	100-300 MW	Any size in modular units	Any size in modular units
Reliability and Uptime	Good	Good	Good	Good	Good [xvi]	Good	Good

Economic Performance [xvii]

	Subcritical Pulverized Coal Combustion (PCC)	Supercritical PCC	Atmospheric Fluidized Bed Combustion	Pressurized Fluidized Bed Combustion	Integrated Gasification Combined Cycle	Natural Gas Combined Cycle	Natural Gas Combined Heat and Power Cycle
Capital Cost – main process ($/kW)	$**1200**-1500 [xv] $1283 [xviii] $1200 [xix]	**$1275**-1575 [xv] $1322 [xviii] $1200 [xix]	$**1500**-1950 [xv] $1324 [xviii]	$**1725**-2025 [xv] $1429 [xviii]	$**1800**-2100 [xv] $1798 [xviii] $1800 [xx]	**$1,000**	**$940** [xxi]
Capital Cost – add-ons ($/kW)							
FGD	$**105**-180 [xv] $158-236 [xxii]	$**105**-180 [xv] $158-236 [xxii]	N/R	N/R	N/R	N/R	N/R
SCR [xv]	$**60**-120	$**60**-120	N/R	N/R	N/R	N/R	N/R
LNB [xv]	$**7.5**-15	$**7.5**-15	$**7.5**-15	$**7.5**-15	Std.	Std.	Std.
Total Capital Cost ($/kW)	**1373**	**1448**	**1508**	**1733**	**1800**	**1000**	**940**
(Sum of bold numbers above used in total capital cost)							
Return (%)	15%	15%	15%	15%	15%	15%	15%
Life (yrs)	35	35	35	35	35	35	35
Total Capital Cost ($/MWh)	23.68	24.97	26.01	29.89	31.06-34.94	17.25	16.22
(Note: No Tax, No Depreciation)							
Operating Cost ($/MWh)							
Labour [xxiii]	2.08	2.08	2.32	2.77	2.77-3.12	2.08	2.08
Other (100% of labour)	2.08	2.08	2.32	2.77	2.77-3.12	1.63	2.08
Energy (GJ/MWh)	10.9	9.5	10	8.6	8.0	6.9	6
$/GJ [xvii] [xxiv] [xxv]	**1.18**	**1.18**	**1.18**	**1.18**	**1.18**	**4.00**	**4.00**
Energy Cost ($/MWh)	12.86	11.21	11.80	10.15	9.44	27.60	24.00
Operating Cost – add ons ($/MWh)							
FGD [xxii]	2.6	2.6					
Total Operating ($/MWh)	19.62	17.97	16.44	15.69	14.98 - 15.67	31.31	28.16
Overall levelized cost to produce electricity ($/MWh)	**43.30**	**42.94**	**42.45**	**45.58**	**46.04-50.61**[xxvi]	**48.56**	**44.38**

Rank

(1=Best, 7=Worst)

	Subcritical Pulverized Coal Combustion (PCC)	Supercritical PCC	Atmospheric Fluidized Bed Combustion	Pressurized Fluidized Bed Combustion	Integrated Gasification Combined Cycle	Natural Gas Combined Cycle	Natural Gas Combined Heat and Power Cycle
Efficiency/GHG Ranking	7	5	6	4	3	2	1
Sulphur Removal Ranking	7	6	5	4	3	2	1
NO_x Control Ranking	7	6	4	5	3	2	1
PM Emission Ranking	7	6	5	4	3	2	1
Mercury Emission Ranking	7	6	5	4	3	2	1
CO_2 Sequestration Ranking	More Difficult	More Difficult	More Difficult	Less Difficult	Less Difficult	More Difficult	More Difficult
Capital Cost Ranking	3	4	5	6	7	2	1
Operating Cost Ranking	5	4	3	2	1	7	6
Overall Cost to Produce Ranking	3	2	1	4	6	7	5

Table Footnotes

[i] Environmental performance characteristics described are at the plant site only. These values do not consider any "upstream" impacts, such as from coal mining operations, natural gas production and processing.
[ii] IEA Greenhouse Gas R&D Program, "Greenhouse Gas Emissions from Power Stations - Pulverized Coal Power Plant," http://www.ieagreen.org.uk/emis4.htm, 40% efficiency emits 830 kg/MWh and 43% efficiency emits 770 kg/MWh.
[iii] Southern Illinois University, Coal Research Center, "Pressurized Fluidized Bed Combustion," www.siu.edu/~coalctr/presfbc.htm.

[iv] Application of terms of the U.S. EPA standard would result in at least 70% removal of sulphur, or about twice what would be required with Alberta standards and Alberta's coal.
[v] From EPCOR's EIA for Genesee 3.
[vi] Based on ratio of efficiencies (33% vs. 38%).
[vii] See Nova Scotia Power's website: http://www.nspower.ca/OurEnvironment/EmissionControls/. Port Aconi Power Plant in Nova Scotia removes 90% of the sulphur and 60% of NO_x.
[viii] Southern Illinois University, Coal Research Center, "Atmospheric Fluidized Bed Combustion," www.siu.edu/~coalctr/atmosfbc.htm.
[ix] IEA Greenhouse Gas R&D Program, "Greenhouse Gas Emissions from Power Stations-Integrated Gasification Combined Cycle," http://www.ieagreen.org.uk/emis6.htm.
[x] IEA Greenhouse Gas R&D Program, "Greenhouse Gas Emissions from Power Stations-Natural Gas Combined Cycle," http://www.ieagreen.org.uk/emis5.htm based on 25 ppm (~ 18g/GJ).
[xi] "Sorbent Injection Systems," www.siu.edu/%7ecoalctr/sorbinj.htm.
[xii] Southern Illinois University, Coal Research Center, "Post Combustion NO_x Control Technologies: Selective Catalytic Reduction Systems," http://www.siu.edu/~coalctr/postcomb.htm.

[xiii] Environmental Working Group, Clean Air Network and Natural Resource Defense Council, "Mercury Falling: An Analysis of Mercury Pollution from Coal-Burning Power Plants," June 2001, Washington DC.

[xiv] CO_2 is recovered at the large gasification project at Great Plains, Dakota and injected into underground reservoirs for enhanced oil recovery at Weyburn, Saskatchewan. See Dakota Gasification Company website: http://www.dakotagas.com/ and http://ens.lycos.com/ens/jul2000/2000L-07-14-11.html.
[xv] Energy Issues (The World Bank) No.14 August 1998, " Technologies for Reducing Emissions in Coal-Fired Power Plants" by Masaki Takahashi, http://www.worldbank.org/html/fpd/energy/enls14.pdf. Costs in $US converted to $Cdn at 1.50 exchange rate (1995$).
[xvi] Wabash River (one of the U.S. IGCC Demonstration Projects) has begun repaying the DOE and has also achieved 79% overall reliability in 1999, "Clean Coal Today" Newsletter of the Office of Fossil Energy, U.S. DOE, DOE/FE-0215P-39 Issue No. 39, Spring 2000.
[xvii] All currency in Canadian dollars.
[xviii] From EPCOR's EIA for Genesee 3, Vol.1, Figure 2.2.1.
[xix] Calculation based on the average of Keephills and Genesee 3 expansions.
[xx] This number represents the actual cost of constructing the greenfield IGCC Polk Power Plant. U.S. DOE Publication "Techline DOE Sponsored Clean Coal Project Wins Power Magazine 1997 Award," June 5, 1997, U.S. Department of Energy.
[xxi] Calculated from TransCanada Pipeline's Press Release for the Redwater and Carseland Cogeneration Projects.
[xxii] Southern Illinois University, Coal Research Center, "Dry Flue Gas Desulfurization." http://www.siu.edu/%7ecoalctr/dryfluegas.htm. $US converted to $Cdn at 1.50 exchange rate (1995$).
[xxiii] For the PCC options, cost of labour ($2.08/MWh) has been calculated using information from EPCOR's Genesee 3 Expansion EIA: 60 people, 440 MW, $120,000 per person per year and 90% load factor. This labour cost has been assumed the same for the two natural gas options. Labour for IGCC and PFBC has been determined using EPCOR's staffing model (60 people) and adding 15 more operators and 5 more maintenance/technical staff to handle the additional complexity of the IGCC and PFBC plants. Labour for AFBC assumes adding 5 more operators and 2 more maintenance/technical staff.
[xxiv] Coal prices from the Coal Association of Canada Website 1998 Prices FOB Vancouver or see also Fording Coals 2000 Annual Report: $US 35.50/t ($Cdn 53.25/tonne), less transportation at approx. $32/tonne (Vancouver - Edmonton), 18 GJ/tonne gives $Cdn 1.18/GJ. This assumes that value of coal in Edmonton area is related to world market prices for coal.
[xxv] Gas price based on approximate daily AECO prices for June 28, 2001 from http://www.gasalberta.com/WebPublish/Web-Gas%20Price.htm
[xxvi] Lower range of values for IGCC based on same reliability/uptime as for the other options. Higher range of values based on 11% worse reliability of IGCC when compared to the other options.

Glossary of Terms used in Tables

AFBC - Atmospheric Fluidized Bed Combustion

BACT - Best Available Control Technology

CC - Coal Combustion

CO_2 - Carbon Dioxide

ESP - Electrostatic Precipitators

FGD - Flue Gas Desulphurization

GHG - Greenhouse Gases

GJ - Gigajoule

IGCC - Integrated Gasification Combined Cycle

kg - kilogram

LNB - Low NOx Burners

MWh - Megawatt per hour

NGCC - Natural Gas Combined Cycle

NO_x - Nitrogen Oxides

NR - not required

PCC - Pulverized Coal Combustion

PFBC - Pressured Fluidized Bed Combustion

PM - Particulate Matter

ppm - parts per million

SCR - Selective Catalytic Reduction

SO_2 - Sulphur Dioxide

SO_x - Sulphur Oxides