TECHNICAL REVIEW OF MERCURY TECHNOLOGY OPTIONS FOR CANADIAN UTILITIES – A REPORT TO THE CANADIAN COUNCIL OF MINISTERS OF THE ENVIRONMENT

Final Report

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NOMENCLATURE

A/C	air-to-cloth (ratio)
ACI	activated carbon injection
AHPC	advanced hybrid particulate collector
ALC	activated Luscar char
APCD	air pollution control device
APH	air preheater
ASTM	American Society for Testing and Materials
B&W	Babcock & Wilcox
BPEI	Babcock Power Environmental Inc.
c-ESP	cold-side electrostatic precipitator
CCME	Canadian Council of Ministers of the Environment
CCS	Coal Creek Station
CEA	Canadian Electricity Association
CFB	circulating fluid bed
CHX	condensing heat exchanger
CMM	continuous mercury monitor
CWS	Canada-Wide Standard
dscm	dry standard cubic meters
DOE	U.S. Department of Energy
EERC	Energy & Environmental Research Center
EPA	U.S. Environmental Protection Agency
EPG	electric power generation
EPW	Environment and Public Works
ERT	emission reduction technology
ESP	electrostatic precipitator
FBC	fluidized-bed combustion
FF	fabric filter
FGD	flue gas desulfurization
FOB	free on board, freight on board
FSI	furnace sorbent injection
GE EER	General Electric Energy and Environmental Research Corporation
GHG	greenhouse gas
GRE	Great River Energy
GTI	Gas Technology Institute
h-ESP	hot-side electrostatic precipitator
HAP	hazardous air pollutants
HiPPS	high-performance power system
HRSG	heat recovery steam generator
IAC	iodine-impregnated activated carbon
ICAC	Institute of Clean Air Companies

NOMENCLATURE (continued)

ICR	Information Collection Request
IFCC	indirectly fired combined cycle
IFGT	integrated flue gas treatment
IGCC	integrated gasification combined cycle
INEEL	Idaho National Engineering and Environmental Laboratory
LAC	lignite-based activated carbon
LIFAC	limestone injection into the furnace reactivation of calcium
LNB	low-NO_x burner
LOI	loss on ignition
LTO	low-temperature oxidation
MACT	maximum achievable control technology
MAG	Multistakeholders Advisory Group
MCWSDC	Mercury Canada-Wide Standard Development Committee
ME	mist eliminator
MerCAP™	mercury control via adsorption process
MSW	municipal solid waste
MWC	municipal waste combustor
NETL	National Energy Technology Laboratory
NODA	Notice of Data Availability
O&M	operating and maintenance
OFA	overfire air
OH	Ontario Hydro
PAC	powdered activated carbon
pc	pulverized coal
PCD	particulate control device
PCO	photochemical oxidation
PE	purchased equipment
PJ	pulse jet
ppb	part per billion
ppm	part per million
PRB	Powder River Basin
QA/QC	quality assurance/quality control
RFP	request for proposal
ROFA	rotating opposed fireair
RoR	rate-of-return
SCR	selective catalytic reduction
SDA	spray dryer absorber
SEA	sorbent enhancement additive
SFS	slagging furnace system
SNCR	selective noncatalytic reduction
SRI	Southern Research Institute
TCC	total capital costs

NOMENCLATURE (continued)

TCR	total capital requirement
TDF	tire-derived fuel
TXU	Texas Utilities
UBC	unburned carbon
UDCP	Uniform Data Collection Program
WFGDS	wet scrubber flue gas desulfurization system
WPPI	Wind Power Production Incentive
WPS	wet particulate scrubber
WRI	Western Research Institute

CONVERSION FACTORS

American dollars versus Canadian dollar: All cost values reported in this report are cited in U.S. dollars because the majority of data that exist for mercury measurement and associated costs comes from the United States. NOTE: At the time of this report, the currency exchange rate was US$1.00:CAN$0.82.

°F = (5/9) (°C − 32)

°C = 9/5 °F + 32

1 metric ton (tonne) = 1.1023 short tons

1 kilogram = 2.2046 pounds

1 pound = 0.4536 kilograms

1 metric ton (tonne) = 1000 kilograms

1 short ton = 0.9072 metric ton (tonne)

$m^3 = 35.314\ ft^3$

kg/Macm = 0.0624 lb/Macf

1 Btu = 1055.06 Joule

1 gigajoule = 1,000,000,000 joules

1 petajoule = 1,000,000 gigajoules

1 petajoule = 10^{12} MWh

1 kilowatt-hour = 1000 watt-hours

1 megawatt-hour = 1000 kilowatt-hours or 1,000,000 watt-hours

1 gigawatt-hour = 1000 megawatt-hours or 1,000,000,000 watt-hours

TECHNICAL REVIEW OF MERCURY TECHNOLOGY OPTIONS FOR CANADIAN UTILITIES – A REPORT TO THE CANADIAN COUNCIL OF MINISTERS OF THE ENVIRONMENT

EXECUTIVE SUMMARY

The purpose of this project is to provide a technical review and evaluation of various mercury control technologies, including maturity, commercial availability, effectiveness, and relative economy, with a focus on the applicability to coal-fired facilities within the Canadian provinces of Alberta, Manitoba, New Brunswick, Nova Scotia, and Saskatchewan. It should be recognized at the beginning that there are a number of challenges related to mercury measurement and control including the following issues:

- Flue gas mercury chemistry can be highly variable.

- Control is more challenging for mercury than for other typical pollutants (i.e., SO_x, NO_x) because of extremely low concentrations in high volumes of flue gases.

- Low concentrations result in mass-transfer limitations, and reactions are generally kinetically limited.

- Changes in flue gas composition may vary or change the form and reactivity of mercury.

Information and data on mercury are also limited by the accuracy of existing instrumentation and measurement techniques and the quantity of available test data. For example, no continuous mercury emissions or field test demonstration data are available for coals and plants specific to the Canadian provinces that were a part of this review.

Performance of control technologies can be highly variable because of differences in coal, plant design configuration, and operation. The data utilized and presented in this document represent a review of available data and knowledge of mercury control, recognizing that the amount of mercury data is expected to grow rapidly over the next 5 to 10 years. While this document provides general indications of performance that can be expected for technologies applied to different coal and plant configurations, there are likely applications that fall outside these reported typical ranges and values.

Because of the complexity of mercury chemistry, Canada and the United States have been grappling with the issue of appropriate mercury regulation for the coal-fired electric power generation (EPG) sector for more than a decade. Throughout the last decade, Canada has pursued the development of appropriate standards through a multi-stakeholder regulatory process that will result in a Canada-Wide Standard (CWS) for mercury reduction from a number of mercury sources, including coal-fired electric power generation plants. The Canadian Council of Ministers of the Environment (CCME) appointed the Mercury Canada-Wide Standard Development Committee (MCWSDC) to specifically review the scientific, technical, and economic status of mercury control technologies to facilitate this process. The MCWSDC receives input from many sources, including a Multistakeholders Advisory Group (MAG) consisting of government officials, utilities, nonprofit conservation/environmental groups, and researchers, all dedicated toward finding a workable solution to lower mercury emissions in the near future. To assist in this process, CCME requested that the University of North Dakota Energy & Environmental Research Center (EERC) provide a technical review of technologies that are applicable to coal-fired EPG plants within Alberta, Manitoba, New Brunswick, Nova Scotia, and Saskatchewan.

Additionally, throughout this period, various groups within the United States have conducted a number of critical studies and field tests related to health and control, which served as the premise or foundation for a number of legislative actions in the United States. Among these is the Clear Skies bill, which was reintroduced by Senate Environment and Public Works (EPW) Committee Chair James Inhofe (R-Oklahoma) (Clean Air Compliance, 2005), and which failed to pass committee on March 9, 2005. The U.S. Environmental Protection Agency (EPA) released the long-awaited Clean Air Mercury Rule on March 15, 2005, using a two-stage cap-and-trade approach that couples this rule with the Clear Air Interstate Rule. Initially, mercury reduction will be facilitated mostly by copollutant control of SO_x and NO_x. The effect will be to reduce overall mercury emissions to 38 U.S. tons by 2010 and to 15 tons by 2018, resulting in a reduction of 70% of present U.S. emissions.

In comparison to the United States, Canada burns proportionately much less coal for electric production, as shown in Figure ES-1 (Miller and Atten, 2005). Annual mercury emissions from coal-fired EPG plants in Canada and the United States are estimated to be 1935 kg and 44,231 kg, respectively (Miller and Atten, 2005).

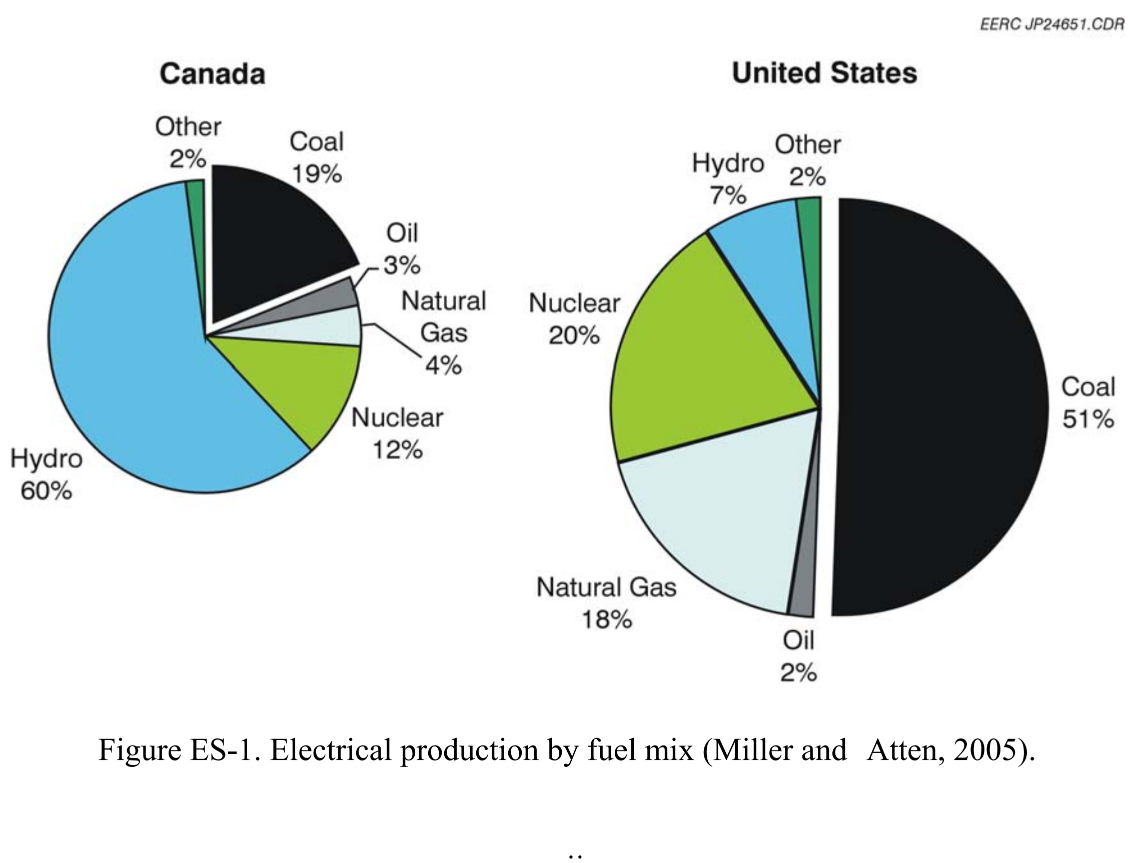

Figure ES-1. Electrical production by fuel mix (Miller and Atten, 2005).

Utility plants throughout Canada burn a variety of lignite, subbituminous, and bituminous coals, plus blends of bituminous, subbituminous, and petcoke, as shown in Figure ES-2. Both the amount of mercury that is in the coal and the form of mercury that is produced during electrical generation is important relative to the amount and speciation of mercury that is emitted. Test data show that the unique characteristics of each coal type result in the generation of different proportions and forms of elemental mercury (Hg^0), oxidized mercury (Hg^{2+}), and particulate-bound mercury (Hg(p)). As can be seen from Table ES-1, subbituminous coals have, on average, a much lower concentration of mercury as compared to other coal types. However, as discussed later, this does not necessarily mean that the amount of mercury that is emitted is less than the other types. Low-rank coals such as subbituminous and lignite produce primarily Hg^0, greater than 70%, which is more challenging to control.

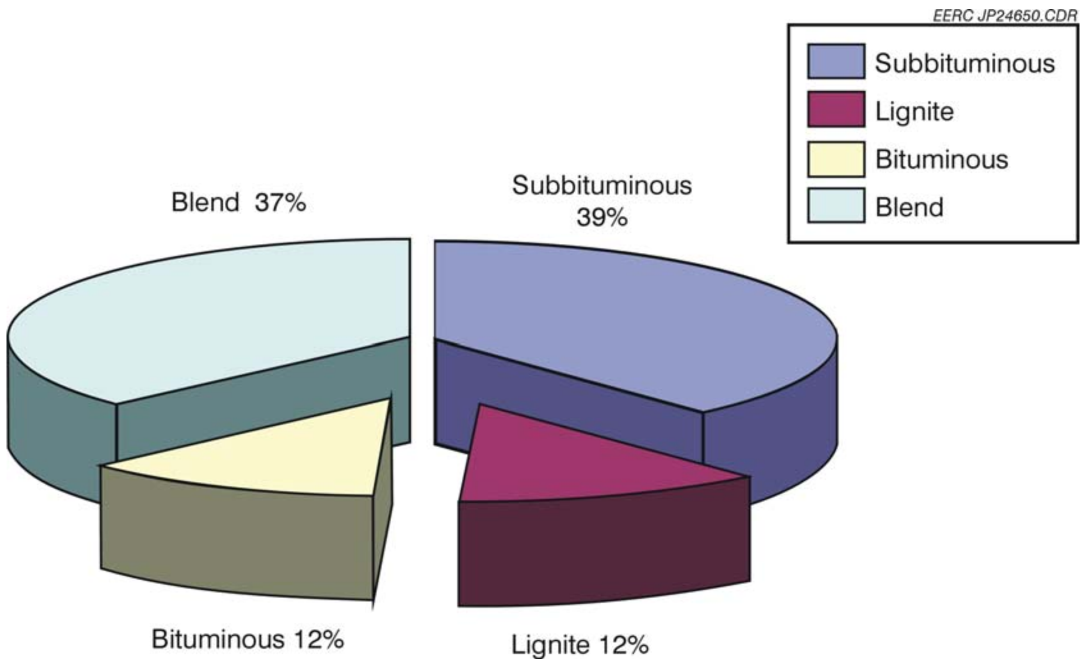

Figure ES-2. Percent of coal combusted by coal-fired electric generation utilities in Canada.

Table ES-1. Mercury Content of Canadian and U.S. Coals by Rank (Miller and Atten, 2005)

Coal Rank	Average Mercury Content	Range of Measured Hg Concentrations
Bituminous	**13.28 mg/MWh (8.59 lb/trillion Btu)**	**0.07–160.67 mg/MWh (0.04–103.81 lb/trillion Btu)**
Subbituminous	**8.89 mg/MWh (5.74 lb/trillion Btu)**	**0.61–110.02 mg/MWh (0.39–71.08 lb/trillion Btu)**
Lignite	**16.30 mg/MWh (10.54 lb/trillion Btu)**	**1.44–270.22 mg/MWh (0.93–75.06 lb/trillion Btu)**

Mercury emissions from coal-fired EPG plants will also vary from plant to plant, depending on the degree of incidental capture that occurs. This capture is generally referred to as "natural" (native or inherent) capture. In addition to the form of mercury, the degree of capture is highly dependent on the type of plant (pc [pulverized coal]-fired, IGCC [integrated gasification combined cycle], CFB [circulating fluidized bed]), the design, operations, and technologies that are installed to reduce NO_x, SO_x, and particulate emissions. Table ES-2 shows a general description of the plants that were considered as part of this review. All units shown are pc-fired, except for Point Aconi which is a CFB and is equipped with a fabric filter (FF) for particulate control. All other units are equipped with hot- or cold-side electrostatic precipitators (ESPs) (h-ESPs or c-ESPs) for particulate control. The only plant that is equipped with a wet scrubber is Belledune. Most of the units have some form of NO_x control, such as low-NO_x burners.

Several years ago, the Canadian Electricity Association (CEA) established a mercury program under which each utility was to separately evaluate its current level of mercury control. These data were compiled over several quarters and are posted on the CEA Web site at www.ceamercuryprogram.ca. These data, along with data received from Dr. Keith Curtis (Curtis Environmental Consulting), served as the basis for the technology review and mercury data presented throughout this report. The mercury content between coals and emissions from plant to plant can be quite varied, as shown in Tables ES-2 and ES-3.

Note that values shown in Table ES-2 for mercury concentration in the coal are from samples of coal that were taken during the mercury speciation stack tests. Although these values are representative, in some cases they differ from the average CEA values shown in the adjacent column or reported elsewhere. As seen in Table ES-2, the lower-rank coals tend to produce more Hg^0, as stated earlier. The values shown in Table ES-2 follow the same trend that was revealed through the EPA information collection request (ICR) data (U.S. EPA, 1999). That is, lignite coal produces flue gases which typically have >80% Hg^0, compared to subbituminous, >65%, and bituminous, <50%. Blends of higher-rank, higher-chlorine coal, or petcoke, with lower-rank, lower-chlorine coals tend to produce flue gas with lower proportions of Hg^0 and higher amounts of oxidized mercury. To effectively remove these diverse forms, different control technologies and approaches are needed.

An applicability-focused technical evaluation of various mercury control technologies, including maturity, availability, effectiveness, and relative economy, was performed based on data presented in Table ES-2 and current levels of mercury control. The criteria used in this review were as follows:

- *Applicability* – Based on coal type, plant design and configuration, quantity and form of mercury currently being emitted, and level of control required. Technical advantages, disadvantages, limits, and constraints based on unit design and coal type were considered.

Technology Effectiveness – Effectiveness in terms of percentage of mercury removed, which is highly dependent on application.

Table ES-2. Description of Power Stations in Alberta, Manitoba, New Brunswick, Nova Scotia, Saskatchewan

Power Station	Net MW Cap[1]	Coal Type	PM[2] Control	Ash Sale	Avg. CEA Coal	Stack Test Data			
						Coal	Hg Emissions Speciation, %		
					Hg, dppm[3]	Hg, dppm	Hg(p)	Hg^0	Hg^{2+}
ALBERTA									
ATCO Power Canada Ltd.									
Battle River	**675**	Subbit.		Yes	0.040	0.041	1%	70%	29%
Unit 3	150		c-ESP						
Unit 4	150		c-ESP						
Unit 5	375		c-ESP				1%	70%	29%
Sheerness[4]	**766**	Subbit.		Yes 10%	0.060	0.036	1%	73%	26%
Unit 1	383		c-ESP				1%	73%	26%
Unit 2	383		c-ESP				1%	73%	26%
EPCOR Generation Inc.									
Genesee	**1182**	Subbit.		Yes	0.043	0.047	0%	96%	4%
Unit 1	381		c-ESP	Yes			0%	96%	4%
Unit 2	381		c-ESP	Yes			0%	96%	4%
Unit 3	450		SDA[5]–FF	No					
Milner Partnership (Milner Power Station)									
Operate to 2012 1	**143**	Bit.	FF						
TransAlta									
Keephills	**766**	Subbit.		No		0.056[6]	0%	95%	5%
Unit 1	383		c-ESP						
Unit 2	383		c-ESP						
Sundance	**2020**	Subbit.		Yes	0.070	0.056	0%	95%	5%
Unit 1	282		c-ESP						
Unit 2	282		c-ESP						
Unit 3	352		c-ESP						
Unit 4	352		c-ESP						
Unit 5	352		c-ESP			0.056	0%	95%	5%
Unit 6	400		c-ESP			0.056	0%	95%	5%
Wabamun	**538**	Subbit.		Yes	0.051	0.051			
Decommissioned 1	62		FF						
Decommissioned 2	57		h-ESP						
Decommissioned 3	140		h-ESP						
Operate to 2010 4	279		h-ESP						

1 http://www.nrcan-rncan.gc.ca//es/etb/cetc/combustion/cctrm/htmldocs/map_electrical_utility_e.html.
2 Particulate matter.
3 Based on CEA 2001 data.
4 Co-owned by ATCO Power and TransAlta Corp.
5 Spray dryer absorber.
6 Assumed to be the same as Sundance.
7 Brandon Units 1-4 decommissioned in 1996.
8 Wet flue gas desulfurization system
9 Data from SaskPower.
10 Value is from EERC pilot-scale test samples; speciation is average of Boundary Dam, consistent with EERC data.

Continued . . .

Table ES-2. Description of Power Stations in Alberta, Manitoba, New Brunswick, Nova Scotia, Saskatchewan (continued)

Power Station	Net MW Cap[1]	Coal Type	PM[2] Control	Ash Sale	Avg. CEA Coal Hg, dppm[3]	Stack Test Data: Coal Hg, dppm	Hg Emissions Speciation, %: Hg(p)	Hg^0	Hg^{2+}
MANITOBA									
Manitoba Hydro									
Brandon[7] Unit 5	**95**	Subbit.	c-ESP	No	0.080	0.075	0%	88%	12%
NEW BRUNSWICK									
New Brunswick Power Corporation									
Belldune BLD2	**450**	82% Bit./ 18% Coke	h-ESP–WFGDS[8]	Yes	0.043	0.033	4%	81%	16%
Grand Lake (op to 2010)	**60**	Bit.	c-ESP						
NOVA SCOTIA									
Nova Scotia Power Inc.									
Lingan	**600**	75% Bit./Sub.– 25% Coke		No	0.053	0.079	0%	41%	59%
Unit 1	150		c-ESP				0%	41%	59%
Unit 2	150		c-ESP				0%	41%	59%
Unit 3	150		c-ESP						
Unit 4	150		c-ESP						
Point Aconi	**165**	74% Pet-Coke/26% Bit./Sub.	FF (CFB)	No	0.027	0.032	3%	31%	66%
Point Tupper	**150**	81% Bit./Subbit. –19% Coke	c-ESP	No	0.049	0.056	0%	44%	55%
Trenton	**310**	Bit./Subbit.		No					
Unit 5	150	99% Bit./Subbit.	c-ESP		0.097	0.093	0%	39%	61%
Unit 6	160	69% Bit./Sub.– 31% Coke	c-ESP		0.040	0.051	1%	46%	53%

1 http://www.nrcan-rncan.gc.ca//es/etb/cetc/combustion/cctrm/htmldocs/map_electrical_utility_e.html.
2 Particulate matter.
3 Based on CEA 2001 data.
4 Co-owned by ATCO Power and TransAlta Corp.
5 Spray dryer absorber.
6 Assumed to be the same as Sundance.
7 Brandon Units 1-4 decommissioned in 1996.
8 Wet flue gas desulfurization system
9 Data from SaskPower.
10 Value is from EERC pilot-scale test samples; speciation is average of Boundary Dam, consistent with EERC data.

Continued . . .

Table ES-2. Description of Power Stations in Alberta, Manitoba, New Brunswick, Nova Scotia, Saskatchewan (continued)

Power Station	Net MW Cap[1]	Coal Type	PM[2] Control	Ash Sale	Avg. CEA Coal Hg, dppm[3]	Stack Test Data Coal Hg, dppm	Hg Emissions Speciation, % Hg(p)	Hg^0	Hg^{2+}
SASKATCHEWAN									
SaskPower									
Boundary Dam	**814**	Lignite		Yes	0.112	0.119	0%	83%	17%
Unit 1	62		c-ESP			0.11	0%	83%	17%
Unit 2	62		c-ESP			0.11			
Unit 3	139		c-ESP						
Unit 4	139		c-ESP						
Unit 5	139		c-ESP			0.124	0%	84%	16%
Unit 6	273		c-ESP			0.114[9]	2%	73%	25%
Poplar River	**562**	Lignite		No	0.139	0.138[10]	0%	80%	19%
Unit 1	281		c-ESP						
Unit 2	281		c-ESP						
Shand	279	Lignite		Yes	0.115	0.108[9]	0%	92%	8%
Unit 1	**279**		c-ESP		0.115	0.108[9]	0%	92%	8%

1 http://www.nrcan-rncan.gc.ca//es/etb/cetc/combustion/cctrm/htmldocs/map_electrical_utility_e.html.
2 Particulate matter.
3 Based on CEA 2001 data.
4 Co-owned by ATCO Power and TransAlta Corp.
5 Spray dryer absorber.
6 Assumed to be the same as Sundance.
7 Brandon Units 1-4 decommissioned in 1996.
8 Wet flue gas desulfurization system
9 Data from SaskPower.
10 Value is from EERC pilot-scale test samples; speciation is average of Boundary Dam, consistent with EERC data.

- *Technology Cost* – The cost of implementing a technology includes both operating and capital cost. Since most of the mercury control technologies are still in the testing and development stage, cost information is limited and not based on actual commercial implementation; therefore, the data presented must be treated as preliminary.

- *Commercial Maturity* – Commercial maturity (or readiness) is a vital criterion, as it provides an indication as to performance uncertainty and the risk related to technology implementation. Technologies that have only been tested on bench- and pilot-scale systems are considered to be high risk and, generally, will not be considered commercially available until larger-scale or full-scale demonstrations have been performed or until a number of systems have been installed. Note, to date, full-scale demonstration of mercury control technologies has not occurred at any of the plants that were included in this review. The total development time from bench- to pilot- to full-scale testing and commercialization for a new technology is typically 6 years (U.S. Congress, 1990). Even then, balance-of-plant impacts may not be fully understood until after a year or more of full-scale operation.

Table ES-3. Estimated Canada Mercury Power Plant Emissions (Miller and Atten, 2005)

	Electricity Generation, MWh	Mercury Emissions, kg	Mercury Emission Rate, mg/MWh
Alberta			
Battle River	4,867,000[a]	108	22
Genesee	n/a	83	5[b]
HR Milner	790,000[a]	6	7
Keephills	n/a	108	17[b]
Sheerness	5,810,000[a]	77	13
Sundance	n/a	275	19[b]
Wabamun	n/a	153	39[b]
Manitoba			
Brandon GS	273,053	5	19
New Brunswick			
Belledune,	3,616,790	12	3
Grand Lake	449,388[c]	106	24
Nova Scotia			
Lingan	n/a	104	27[b]
Point Aconi	n/a	1	1[b]
Point Tupper	n/a	15	12[b]
Trenton	n/a	43	25[b]
Ontario			
Atikokan	823,000	38	46
Lakeview	2,455,000	46	19
Lambton	10,455,000	130	12
Nanticoke	22,236,000	241	11
Thunder Bay	1,522,000	72	47
Saskatchewan			
Boundary Dam	6,057,364	191	32
Poplar River	4,457,200	116	26
Shand Power	2,150,000	56	26

[a] Net generation obtained from ATCO Power report *Environment, Health and Safety Review 2002* at http://www.atcopower.com/Environment_Health_&_Safety/Reports/environmental_reports.htm.
[b] 2002 annual generation was not available, so output emission rates are for 2001 and calculated from generation data in power plant information reports available from the CEA at http://www.ceamercuryprogram.ca/index.htm
[c] Net generation estimated assuming Grand Lake was in operation 90% of the time during 2002. See the methodology discussion in the Appendix to Miller and Atten 2005.

- *Multipollutant Capable* – The ability of the technology to provide cocontrol of multiple pollutants.

- *Balance-of-Plant Issues* – The impact that the technology will have on upstream and downstream equipment and processes.

- *Environmental and Technical Implementation Issues* – Other issues that may be technical hurdles or environmental concerns.

Using the criteria mentioned above, almost 100 different potential mercury control technologies or approaches were reviewed, evaluated, and summarized. The technologies that were reviewed are further grouped into the following four main categories:

- *Commercially available technologies.* These technologies have been tested at the bench-, pilot-, and full-scale level and will be, or could potentially be, commercially available by 2009. However, it should be recognized that there are more full-scale demonstration data and experience for some fuels versus others, and that additional data may be needed for specific fuels and plant designs to minimize performance uncertainty and ensure commercial readiness. As stated earlier, full-scale demonstration of mercury control technologies has not occurred at any of the plants that were included in this review. Whether a technology is considered commercially available by all groups depends on the level of testing that has been performed thus far and the confidence that providers (vendors) and buyers (utilities) have in this data.

- *Commercially emerging technologies.* These technologies have been tested at the bench- and pilot-scale level and are currently being, or will be, demonstrated at the full-scale level during the next 1–3 years. Some of these technologies may be available by 2009, depending on test schedules and degree of technical and economic success.

- *Developing technologies*. These technologies are defined as those that have only limited testing at the bench- or pilot-scale, but that appear to have the potential for removing significant (>50%–90%) mercury. It is not expected that sufficient demonstration of these technologies would be completed by 2009 and, therefore, would not be commercially available until after 2010.

- *New plant generation technologies.* The technologies listed under this category are applicable for new generation plant construction. The technologies are generally considered commercially available and many of the same mercury control technology options apply as for existing plants.

It should be recognized that while the definitions above imply commercial readiness within a given time period, they do not include or address the time required/needed for commercial deployment. That is, if a technology becomes available in 2009, it will take several years before the technology can be widely deployed. The U.S. Department of Energy (DOE) estimates that mercury control technologies currently under demonstration would be ready for commercial deployment by 2011–2013 (Appendix A).

The technologies in this report, as shown in Appendix B, were technically evaluated using the criteria stated above and the following additional guidelines provided by CCME:

1) The technology could potentially reduce mercury emissions by 50% or more.

2) The technology is, or could potentially be, commercially available by 2009.

3) Other technologies that might be commercially available by 2015 that could potentially reduce mercury emissions by 50%–90%.

As shown in Appendix B, there are several technologies that are, or may be, commercially available by 2009, with differing degrees of performance. Many of these technologies, if employed alone, may result in minimal (5%–25%) reduction in mercury. Table ES-4 shows a list of possible technology options that may be applicable to the plants that were included in this review.

Table ES-4. Promising (P) Technology Options for Power Plants in Alberta, Manitoba, New Brunswick, Nova Scotia, and Saskatchewan

Power Station	Net MW Cap[2]	Coal Type	PM Control	ACI[1]–ESP 50%–60% Lb/Macf Range		ESP–ACI–FF 70%–80% lb/Macf Range		SEAs[3]	Treated Sorb.	Non-carbon Sorb.	Oxid. Tech.	EPRI Mer - CAP™	ALSTOM Mer-Cure™	Coal Clng.	Comb. Mod.
ALBERTA															
ATCO Power Canada Ltd.															
Battle River	**675**	Subbit.													
Unit 3	150		c-ESP	5	10	3	5	P	P	P		?	P	P	P
Unit 4	150		c-ESP	5	10	3	5	P	P	P		?	P	P	P
Unit 5	375		c-ESP	5	10	3	5	P	P	P		?	P	P	P
Sheerness [4]	**766**	Subbit.													
Unit 1	383		c-ESP	5	10	3	5	P	P	P		?	P	P	P
Unit 2	383		c-ESP	5	10	3	5	P	P	P		?	P	P	P
EPCOR Generation Inc.															
Genesee	**1182**	Subbit.													
Unit 1	381		c-ESP	5	10	3	5	P	P	P		?	P	P	P
Unit 2	381		c-ESP	5	10	3	5	P	P	P		?	P	P	P
Unit 3	450		SDA–FF	5	10	← ACI ahead of SDA		P	P	P	P			P	P
Milner Partnership (Milner Power Station)															
Operate to 2012, Unit 1	**143**	Bit.	FF	R2012	R2012	R2012	R2012	R2012/P	R2012	R2012	R2012	R2012	R2012	R2012	P
TransAlta															
Keephills	**766**	Subbit.													
Unit 1	383		c-ESP	5	10	3	5	P	P	P		?	P	P	P
Unit 2	383		c-ESP	5	10	3	5	P	P	P		?	P	P	P
Sundance	**2020**	Subbit.													
Unit 1	282		c-ESP	5	10	3	5	P	P	P		?	P	P	P
Unit 2	282		c-ESP	5	10	3	5	P	P	P		?	P	P	P
Unit 3	352		c-ESP	5	10	3	5	P	P	P		?	P	P	P
Unit 4	352		c-ESP	5	10	3	5	P	P	P		?	P	P	P
Unit 5	352		c-ESP	5	10	3	5	P	P	P		?	P	P	P
Unit 6	400		c-ESP	5	10	3	5	P	P	P		?	P	P	P
Wabamun	**538**	Subbit.													
Decomm. Unit 1	62		FF	Ret.	Ret.			Ret.	Ret.	Ret.	Ret.	Ret.	Ret.	Ret.	Ret.
Decomm. Unit 2	57		h-ESP	Ret.	Ret.			Ret.	Ret.	Ret.	Ret.	Ret.	Ret.	Ret.	Ret.
Decomm. Unit 3	140		h-ESP	Ret.	Ret.			Ret.	Ret.	Ret.	Ret.	Ret.	Ret.	Ret.	Ret.
Operate to 2010, Unit 4	279		h-ESP	R2010	R2010			R2010	R2010	R2010	R2010	R2010	R2010	R2010	P
MANITOBA															
Manitoba Hydro															
Brandon[5] **Unit 5**	**95**	Subbit.	c-ESP	5	10	3	5	P	P	P		?	P	P	P

1 Activated carbon injection
2 http://www.nrcan-rncan.gc.ca//es/etb/cetc/combustion/cctrm/htmldocs/map_electrical_utility_e.html.
3 Sorbent enhancement additive
4 Co-owned by ATCO Power and TransAlta Corp.
5 Brandon Units 1–4 decommissioned in 1996.

Continued . . .

Table ES-4. Promising (P) Technology Options for Power Plants in Alberta, Manitoba, New Brunswick, Nova Scotia, and Saskatchewan (continued)

Power Station	Net MW Cap[2]	Coal Type	PM Control	ACI[1]–ESP 50%–60% lb/Macf Range		ESP–ACI–FF 80%–90% lb/Macf Range		SEAs[3]	Treated Sorb.	Non-Carbon Sorb.	Oxid. Tech.	EPRI Mer-CAP™	ALSTOM-Mer-Cure™	Coal Clng.	Comb. Mod.
NEW BRUNSWICK															
New Brunswick Power Corporation															
Belledune BLD2	**450**	82% Bit./ 18% Coke	h-ESP–WFGDS			1	3	P	P	P	P	P		P	P
Grand Lake (operate to 2010)	**60**	Bit.	c-ESP	R2010	R2010	R2010	R2010	R2010	R2010	R2010	R2010	R2010	R2010	R2010	P
NOVA SCOTIA															
Nova Scotia Power Inc.															
Lingan	**600**	75% Bit./Sub.–25% Coke													
Unit 1	150		c-ESP	4	8	2	4	P	P	P		?	?	?	P
Unit 2	150		c-ESP	4	8	2	4	P	P	P		?	?	?	P
Unit 3	150		c-ESP	Ret.	Ret.	Ret.	Ret.	Ret.	Ret.	Ret.	Ret.	Ret.	Ret.	Ret.	Ret.
Unit 4	150		c-ESP	4	8	2	4	P	P	P		?	?	?	P
Point Aconi	**165**	74% Pet-Coke/26% Bit./Sub.	FF (CFB)	N/A	N/A	Not Req	Not Req	Not Req.	Not Req.	Not Req.	Not Req.	Not Req.	Not Req.	Not Req.	Not Req.
Point Tupper	**150**	81% Bit./Subbit.–19% Coke	c-ESP	4	8	2	4	P	P	P		?	?	?	P
Trenton	**310**	Bit/Subbit		4				P	P	P		?	?	?	P
Unit 5	150	99% Bit./Subbit.	c-ESP	4	8	2	4	P	P	P		?	?	?	P
Unit 6	160	69% Bit./Sub.–31% Coke	c-ESP	4	8	2	4	P	P	P		?	?	?	P

1 Activated carbon injection
2 http://www.nrcan-rncan.gc.ca//es/etb/cetc/combustion/cctrm/htmldocs/map_electrical_utility_e.html.
3 Sorbent enhancement additive
4 Co-owned by ATCO Power and TransAlta Corp.
5 Brandon Units 1–4 decommissioned in 1996.

Continued . . .

Table ES-4. Promising (P) Technology Options for Power Plants in Alberta, Manitoba, New Brunswick, Nova Scotia, and Saskatchewan (continued)

Power Station	Net MW Cap [2]	Coal Type	PM Control	ACI[1]–ESP 50%–60% lb/Macf Range		ESP–ACI–FF 70–80% lb/Macf Range		SEAs[3]	Treated Sorb.	Non-Carbon Sorb.	Oxid. Tech.	EPRI Mer-CAP™	ALSTOM Mer-Cure™	Coal Clng.	Comb. Mod.
SASKATCHEWAN															
SaskPower															
Boundary Dam	**814**	Lignite													
Unit 1	62		c-ESP	5	20	N/A	N/A	P	P	P		?	P	P	P
Unit 2	62		c-ESP	5	20	N/A	N/A	P	P	P		?	P	P	P
Unit 3	139		c-ESP	5	20	N/A	N/A	P	P	P		?	P	P	P
Unit 4	139		c-ESP	5	20	N/A	N/A	P	P	P		?	P	P	P
Unit 5	139		c-ESP	5	20	N/A	N/A	P	P	P		?	P	P	P
Unit 6	273		c-ESP	5	20	N/A	N/A	P	P	P		?	P	P	P
Poplar River	**562**	Lignite													
Unit 1	281		c-ESP	5	20	3	6	P	P	P		?	P	P	P
Unit 2	281		c-ESP	5	20	3	6	P	P	P		?	P	P	P
Shand	279	Lignite													
Unit 1	**279**		c-ESP	5	20	3	6	P	P	P		?	P	P	P

1 Activated carbon injection
2 http://www.nrcan-rncan.gc.ca//es/etb/cetc/combustion/cctrm/htmldocs/map_electrical_utility_e.html.
3 Sorbent enhancement additive
4 Co-owned by ATCO Power and TransAlta Corp.
5 Brandon Units 1–4 decommissioned in 1996.

The only technologies that may prove to be commercially available within the next several years and that could be applied to reduce mercury emissions by more than 50% are 1) fuel switching, 2) conventional coal cleaning, 3) ACI, and for greater control, 4) ACI injected upstream of a newly added FF, and 5) scrubbers. There are other technologies such as halogenated sorbents, SEAs, combustion modifications, oxidation technologies, coal pretreatment technologies, and advanced particulate and scrubber technologies that show great promise but may take longer to demonstrate and should also be considered depending on commercial deployment timelines.

Fuel switching is not a likely option given the availability of the fuel (biomass must be available locally in large quantities) and the cost associated with converting a boiler to fire a different fuel. Switching to natural gas is more of a political decision rather than an economic one, given the significant market price spikes, uncertainty, and the high demand expected for natural gas in the future. Conventional coal cleaning is not likely an option for the plants reviewed, since most of the coal burned is subbituminous and, therefore, cleaning it would not be economical (if credit is only given for Hg reduction) because it is probable that little mercury would be removed. However, there are some mercury removal test results for Alberta coals that have been encouraging with significant economic cobenefits identified. The industry is experienced in regard to applying conventional coal-cleaning techniques to bituminous coals but not lignite and subbituminous coals and, thus, more testing is needed. Using scrubbers as a mercury control is not a likely option because Belledune is the only unit equipped with a scrubber, and it appears cost-prohibitive to install scrubbers solely for mercury control. Technologies such as those offered by Powerspan and Mobotec are also unlikely options to consider unless multipollutant control is required. For additional consideration, many of the plants burn low-rank fuels, which produce a large amount of Hg^0 (refer to Table ES-2) that will not be removed by a scrubber unless an oxidation technology is used upstream. There are several emerging technologies that show promise for upstream oxidation or additional capture downstream that may apply to Belledune in the future. For example, EPRI's MerCap technology is being tested on a larger scale by URS and may prove effective for additional capture downstream of the Belledune scrubber. The initial mercury removal results were promising, but there is a potential of the gold being poisoned by the components in the flue gas. Preliminary results show that a high level of control might be possible with the MerCap technology, but only for specific plants (i.e., those plants with a WFGDS).

For all the remaining units that are equipped with ESPs, the most promising near-term options for consideration in order to meet or exceed mercury removal rates of 50% are 1) installation of an ACI system upstream of the c-ESP or 2) the addition of a polishing FF and installation of ACI between the ESP–FF. To achieve 50%–60% mercury removal, ACI rates upstream of the c-ESP are expected to range from 3 to 10 lb/Macf; for 60%–70% removal, injection is expected to range from 5 to 20 lb/Macf, depending on coal type and plant design. This option may be cost prohibitive if the fly ash is currently sold, because adding AC would alter the characteristics and make the ash unsalable. Additionally, CO_2 offsets may also be lost if the ash is no longer sold for cement replacement. To achieve 70%–90% mercury removal, ACI rates upstream of a newly added FF are expected to range from 2 to 6 lb/Macf, depending on coal type and plant design. While the ranges above are provided for similar coal types, unique characteristics specific to Canadian coals may require more, or less, AC to achieve the targeted removal. To more accurately determine or better define the range of ACI rates needed and thereby reduce performance uncertainty, additional site-specific testing is warranted, especially given that there is no demonstration data available from Canadian plants and coals and only limited data from U.S. full-scale demonstrations. It should be further noted that the ACI ranges stated above do not address, nor imply, cost effectiveness. That is, injecting AC at the high rates shown may be determined to be too costly.

Although more capital-intensive, the addition of an FF has several advantages. First, because ACI would affect only the ash collected in the FF, the bulk of the ash could still be sold (the ESP ash) and, secondly, an FF may provide regulatory flexibility for the utility. If the regulatory level of mercury removal changes, if particulate control becomes more stringent in the future, and/or if new, more efficient mercury sorbents are developed, these changes could be incorporated with an FF with minimal impact on overall plant operations. However, in addition to higher capital costs, operating and maintenance costs associated with the FF include increased power requirements, general maintenance and, most importantly, filter bag replacement (a 5-year bag life is assumed). Another concern is that AC can cause blinding of the bags, resulting in increasing pressure drop and bag-cleaning cycles, thereby shortening bag life. The seriousness of this concern still needs to be evaluated.

The cost estimating methodology, assumptions, and data presented throughout the report are based on estimates and reference data from a DOE report prepared by Hoffman and Ratafia-

Brown (discussed in Section 3). The costs presented should be considered approximate, as a detailed site assessment (design, permitting, or retrofit difficulty assessment) was not performed as part of this review. Based on the assumptions of the DOE report, a first-year cost estimate was performed for each plant for the case when AC is injected upstream of a c-ESP, and when AC is injected upstream of a newly installed (or existing) FF. The capital cost for installing the ACI system was assumed to be 3–4 $/kW for plants above 360 MW, 4–6$/kW for plants between 200 and 360 MW, and 6–9 $/kW for plants 200 MW and less. Capital costs for installing an FF were assumed to be 55–70 $/kW for all plant sizes. A discount rate of 10% was assumed, and a life expectancy of the newly installed equipment was assumed to be 20 years. Note that for plants that have a life expectancy shorter than 20 years, the capital recovery costs that are estimated will be low. Based on these assumptions, Table ES-5 provides a range of cost by coal type for all of the plants that were included in this review. Note, these costs are presented as first-year costs and are not levelized. Additionally, the costs shown in this table do not account for loss of ash sales due to AC contamination. Costs are estimated to increase by a factor of 2–4 for the case of ACI upstream of the ESP, if these costs are accounted. Note, the loss of CO_2 offsets is also not accounted for because the ash will no longer be suitable for concrete use. Thus loss of ash saleability may result in costs even higher than a factor of 2–4.

Point Aconi is already equipped with an FF and is getting greater than 80% mercury control. Injecting a small amount of AC upstream of the existing FF may improve this further. Results from Point Aconi, however, cannot be related to, nor expected for, other plants as the CFB is unique and produces ash and gas compositions that are unlike conventional pc-fired systems equipped with ESPs.

There are several other emerging technologies as shown in Table ES-4 that are being developed that may be commercial within the next 3–5 years that have the potential to provide additional control (70%–90%) at a potentially lower cost. These are 1) the injection of treated AC or other treated sorbents, 2) the use of a halogen-based additive (NaCl or $CaCl_2$) to improve performance, 3) the use of a noble metal system (MerCap), 4) ALSTOM Mer-Cure™ technology, 5) combustion modifications, or 5) advanced coal-cleaning methods. Assuming ACI is implemented first, the injection of a treated sorbent would allow use of the existing equipment.

Table ES-5. Summary of Estimated Technology Cost Ranges for Power Stations in Alberta, Manitoba, New Brunswick, Nova Scotia, and Saskatchewan

	ACI–ESP[1]		ESP–ACI–FF	
Coal Type	**First Year (US$1000/year)**	**First Year (mils/kWh)**	**First Year (US$1000/year)**	**First Year (mils/kWh)**
Bituminous Incl. Blends	740–1,480	0.63–1.23	2,400–9,000	1.98–2.68
Subbituminous	950–4,700	0.74–1.54	2,600–9,100	2.25–2.89
Lignite	450–7,000	0.85–3.29	5,000–6,800	2.31–3.09

Note: Table does not include Brandon Station Values. These costs reflect high and low estimates for all ather plants burning specific coal type. More detailed cost data is shown for each plant in Sections 5–9 of this report.

[1] c-ESP costs do not include loss of ash sales, which could increase costs by a factor of 2–4. Also does not include loss of CO_2 offsets.

Most of the testing to date with halogenated AC has been done using an FF with promising results; however, preliminary results in an EERC pilot-scale test with an c-ESP when firing a subbituminous coal gave 70%–80% at ACI rates of 4.8 and 6.7 lb/Macf. Additional pilot-scale and longer-term, full-scale testing of halogenated AC is needed to determine performance advantages over standard AC and to better understand the ultimate fate of the halogens.

Another potential future option, particularly for coals that produce a high concentration of Hg^0, is the use of a coal additive—usually halogen-based—to change the mercury speciation, thereby improving the performance of the AC. Results from tests on the EERC's laboratory pilot-scale unit (550,000-Btu/hr pc-fired unit) as well as full-scale tests at the Leland Olds Power Station have been promising. At Leland Olds Station, the goal was to obtain 55%–60% mercury removal when a Fort Union lignite was fired. The addition of the additive achieved this level of control with only 3 lb/Macf AC compared to 20 lb/Macf without the additive. Note, however, that tests that were performed for ATCO and EPCOR with a chlorine-based additive using an Alberta subbituminous coal and standard AC did not show the same level of removal, although there was some improvement in the AC performance. While encouraging, standard ACI rates were reduced only by a factor of <2 (Pavlish et al., 2004a, b). Because costs of the additive are about one-fourth that of AC, potential cost savings can be achieved by using additives. The effectiveness of these technologies still must be determined for a wider range of coals and conditions; but based on preliminary results, both the use of treated ACs and halogen-based additives show promise.