2. CANADIAN ELECTRIC POWER GENERATION SECTOR

The following section provides an overview of the existing EGUs in Canada. The units' state of operation including fuel utilization and mercury content will be assessed providing thus, an estimation of total mercury input during normal operation. Air pollution control technologies, currently installed at facilities, will be listed along will their natural mercury capture rate. It will be assessed in concurrence with the reported mercury emissions in the air, water and soil. Following this analysis, Canadian low-mass mercury emitters and peaking units will be identified. Future hypothetical facilities, defined by Environment Canada, will be presented with expected mercury emissions.

2.1 Canadian electricity generation fleet

Electricity is generated in Canada using five technological approaches: hydroelectricity, conventional steam power, nuclear steam power, internal combustion systems and forthcoming renewable energy like wind and tidal power. Electric production units have generated 623 TWh of electricity in 2007 (Tab. 2-1) corresponding to a 9% increase from 1998 total production.[1] Public and private EGUs were responsible for 93.3% of total production. Hydroelectricity and conventional steam power covers 80% of total electricity production originating mostly from Quebec and Ontario. Total production in 2007 represented 57% of nameplate electric generating capacity (124.2 GW) for the entire Canadian fleet.

Table 2-1: Canadian total electricity generation (in terawatt-hours, TWh_e) in 2007 by province and technological approach[2]

Province	Quebec	Ontario	Alberta	British Colombia	Newfound-land	Manitoba	Others [a]	TOTAL
Hydroelectricity	181.1	34.4	2.1	64.3	40.0	33.5	8.6	364.0
Conventional steam	2.6	34.3	50.2	5.0	1.3	0.5	39.5	133.4
Nuclear	4.3	79.8	0	0	0	0	4.1	88.2
Others [b]	4.0	9.8	15.1	2.6	0.3	0.4	5.0	37.2
TOTAL	192.0	158.3	67.4	71.9	41.6	34.4	57.2	622.8

[a] Includes, in order of importance, Saskatchewan, New Brunswick, Nova Scotia, PEI and Canadian territories.
[b] Includes, in order of importance, combustion turbine, internal combustion, wind and tidal electricity production.

Electricity generation by conventional power systems uses coal and petroleum products (incl. natural gas) to produce steam which drives a turbine coupled to a generator. In the past, this method was most important in producing bulk electricity. However, hydroelectricity has rapidly replaced steam power throughout last century as the main electricity generation sector in Canada. For example, as of 1994, the installed capacity for conventional steam power systems represented 25% of total Canadian capacity (18% for coal powered systems).[3] Today, it represents about 22% of total capacity (or 28.4 GW_e), which reflects not only the economic

[1] Canadian Electricity Association, Industry data, 2010.
[2] Statistics Canada, Electric power generation, transmission and distribution report, 2007.
[3] Statistics Canada, Electric power capability and load report, 2003.

value of hydroelectricity but also the arrival of environmentally-friendly technologies like wind power, geothermal energy, solar energy and biomass combustion (Fig. 2-1).

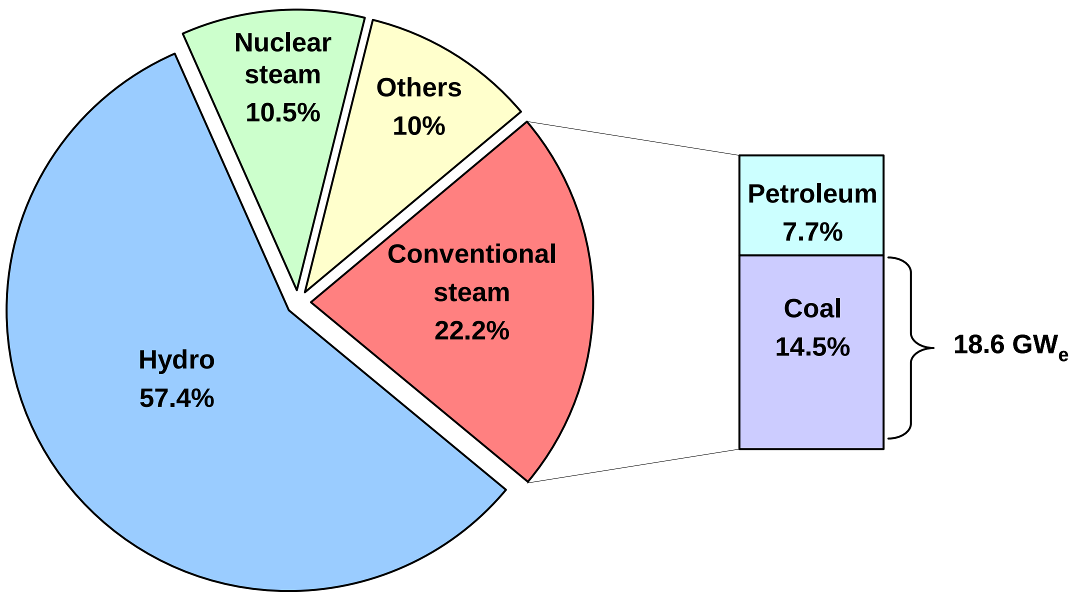

Figure 2-1: Generating capacity of Canadian EGUs by technology (the total electric capacity was 127.8 GW in 2007; others: include combustion turbine, wind, tidal and internal combustion)[4]

2.1.1 Coal-fired EGUs overview

As of 2009, the Canadian coal-fired EGU fleet was composed of 53 boilers built on 21 sites owned by nine power generation companies (Tab. 2-2). The Wabamun unit in Alberta was however decommissioned in March 2010 after 40 years of operation. The Grand Lake remaining unit in New Brunswick was also decommissioned in June 2010. Two units at Lambton and two others at Nanticoke generating stations are expected to be shut down by the end of 2010 due to declining Ontario electricity demand.[5] All remaining facilities in Ontario will be shut down or converted for biomass combustion by the end of 2014 according to the Coal Closure Regulation adopted by Government of Ontario in 2007.[6] Under new climate change legislation, the remaining coal-fired unit in Brandon, Manitoba has been instructed to stop combusting coal for January 2010.[7] By law, it can only use coal to support emergency operations, such as times of drought. All other units listed in Table 2-2 are expected to remain in activity in the near future. The Lakeview coal-fired generating station in Ontario was closed in 2005.

[4] Statistics Canada, Electric power generation, transmission and distribution report, 2007.
[5] Ontario Power Generation Inc., OPG 2009 year in review, 2009.
[6] Government of Ontario Environmental Registry, Coal Closure Regulation O. Reg. 496/07, 2007.
[7] Government of Manitoba, The climate change and emissions reductions act, 2008.

Table 2-2: Canadian coal-fired EGUs (as of 2009) with 2003 electricity production

Operator	EGU	# of units [a]	In-service year	Type of coal	Electricity production	
					Nameplate capacity, MW	Production, GWh [b]
Alberta : 2003 production = 44,615 GWh (43.4% of total Canadian production)						
TransAlta Corp.	Sundance	6	1970–80	sub-bituminous [f]	2,125	15,090 (77%)
	Keephills	2	1983		800	6,030 (85%)
	Wabamun [c]	1	1968		300	1,520 (58%)
Capital Power Corp. [d]	Genesee [e]	3	1989–2005		1,320	10,060 (87%)
ATCO Power Ltd.	Sheerness	2	1986–90		800	6,010 (90%)
	Battle river	3	1969–81		675	4,970 (84%)
Maxim Power Corp.	H.R. Milner	1	1973		160	935 (71%)
Manitoba: 2003 production = 560 GWh (0.6%)						
Manitoba Hydro	Brandon [c]	1	1970	sub-bituminous	105	560 (61%)
New Brunswick: 2003 production = 4,410 GWh (4.3%)						
New Brunswick Power Corp.	Belledune	1	1993	sub-bituminous [g]	480	3,960 (94%)
	Grand Lake [c]	1	1964	bituminous [g]	60	450 (86%)
Nova Scotia: 2003 production = 9,275 GWh (9.1%)						
Nova Scotia Power	Lingan	4	1979-84	bituminous, petroleum coke	630	4,685 (89%)
	Point Aconi	1	1994		210	1,340 (83%)
	Point Tupper	1	1986		150	1,175 (90%)
	Trenton	2	1969, 91		310	2,075 (76%)
Ontario: 2003 production = 32,255 GWh (31.6%)						
Ontario Power Generation Inc.	Atikokan	1	1985	lignite	230	1,035 (47%)
	Lambton	4	1969–70	bituminous [g]	2,050	9,910 (56%)
	Nanticoke	8	1973–78	bituminous, sub-bituminous [f]	4,512	19,850 (50%)
	Thunder Bay	2	1981–82	lignite, sub-bituminous	330	1,460 (51%)
Saskatchewan: 2003 production = 12,625 GWh (11.0%)						
SaskPower	Boundary Dam	6	1959–78	lignite	875	6,120 (80%)
	Poplar River	2	1981–83		615	4,450 (83%)
	Shand	1	1992		300	2,055 (61%)

[a] Boilers in operation in 2009.
[b] Annual electricity production reported in the Uniform Data Collection Program initiated by the CCME in 2003. Value in parenthesis represents the fraction of annual nameplate capacity.
[c] The remaining unit has been decommissioned in 2010.
[d] Previously EPCOR Generation Inc.
[e] The third unit at the Genesee facility is a joint venture with TransAlta Corp.
[f] Natural gas is the secondary/backup fuel.
[g] Petroleum coke is the secondary fuel.

According to the 2003 Uniform Data Collection Program (UDCP) promulgated by the Canadian Council of Ministers of the Environment (CCME), the existing coal-fired steam generation sector (as of 2009) had produced an estimated 104 TWh of electricity which represents 64% of total nameplate capacity of the fleet (18.6 GW_e).[8] In 2007, total production decreased by 7% to 94.3 TWh for this sector according to Statistics Canada whiles the global Canadian electricity output increased by 8%.[9] It will further decline with upcoming closures. As of 2010, Alberta and Ontario were responsible for about 75% of total electricity produced by coal steam power. By 2015, Alberta will become the main player in this sector. Nova Scotia and Saskatchewan follows with about 10% of total production each.

2.1.2 Fuel properties, utilization and mercury content

2.1.2.1 Coal

Mercury is found in all ranks of coal to varying degrees. When coal is burned, it is potentially released into the environment after volatilization. Annual coal consumption by EGUs, the corresponding heating value and mercury content are outlined in Table 2-3 based on reports about facilities operation in the early part of last decade. The coal higher heating value (HHV) and mercury content were obtained from sampling and analysis reports that were part of the Canadian Electricity Association (CEA) mercury program.[10] Established in 2002, this campaign brought significant efforts by coal-fired EGUs to improve mercury emission inventories and evaluate the current level of mercury control. Annual coal utilization was obtained jointly from the CEA program and the CCME mercury CWS development committee.

According to these figures, an estimated 3,000 kilograms of mercury entered coal-fired boilers in 2003. Ontario, Alberta and Saskatchewan with their prominent fleet accounted for most of it. It corresponds to a global emission factor of 29 kg/TWh_e if all mercury was to be released in the air. The mercury input reported in 2003 according to the CEA mercury program differs slightly with the official CWS (3,725 kg) since the provinces adjusted the rates of power generation and mercury emissions observed during the sampling period to better reflect long-term trends. This created a data set tending towards a higher than reported rate of coal usage, power generation and mercury emission.

Total coal utilization in early 2000s approached 60,000 kt annually but declined in recent years to 55,000 kt (2007) owing to reductions in all provinces except Alberta that saw an increase in coal utilization for electricity production (Fig. 2-2).[11] Considering this 8% reduction in coal consumption, the mercury input in 2007 should have approached 2,750 kilograms. Decommissioning of the Wabamun, Grand Lake and four units in Ontario by the end of 2010 should further reduce mercury input to 2,400 kilograms. Total closure of Ontario's coal-fired EGUs by the end of 2014 should bring the total mercury input below 2,000 kilograms.

[8] Canadian Council of Ministers of the Environment, Data analysis in support of the development of a Canada-Wide Standard for mercury emissions from coal-fired electric power generation plants, August 2005.
[9] Statistics Canada, Electric power generation, transmission and distribution report, 2007.
[10] Canadian Electricity Association, CEA mercury program website.
[11] Statistics Canada, Electric power generation, transmission and distribution report, 2007.

Table 2-3: Coal properties by Canadian EGUs based on 2002–2005 data from the CEA mercury program

EGU	Primary fuel location	Annual use (Mt)	HHV input (MW_{th})	Fuel efficiency (%)	Annual mercury input	
					kg	kg/TWh_e
Sundance	Alberta	9,010	5,275	32	505	35
Keephills	Alberta	2,355	1,400	49	132	22
Wabamun	Alberta	2,105	1,150	15	107	71
Genesee [a]	Alberta	5,165	3,025	38	182	18
Sheerness	Alberta	3,695	2,030	34	166	28
Battle River	Alberta	3,220	1,860	28	97	22
H.R. Milner [b]	Alberta	585	340	32	18	19
Brandon	Powder River Basin	255	220	29	18	32
Belledune [c]	South America	1,575	1,350	34	63	16
Grand Lake [d]	New Brunswick	150	130	39	11	25
Lingan	US, South America	1,650	1,490	36	74	16
Point Aconi	US, South America	450	445	35	8	6
Point Tupper	US, South America	440	400	34	16	14
Trenton	US, South America	770	670	35	46	22
Atikokan	Saskatchewan	660	345	31	39	41
Lambton	Eastern US	3,520	3,260	35	244	25
Nanticoke [e]	Powder River Basin Eastern US	9,215	6,615	34	477	24
Thunder Bay [f]	Saskatchewan Powder River Basin	980	560	30	51	35
Boundary Dam	Saskatchewan	6,580	2,300	30	322	53
Poplar River	Saskatchewan	5,710	1,505	34	316	71
Shand	Saskatchewan	2,105	720	33	109	53
Alberta		**26,140**	**15,080**	**33**	**1,207**	**28**
Manitoba		**255**	**220**	**29**	**18**	**32**
New Brunswick		**1,725**	**1,480**	**35**	**74**	**17**
Nova Scotia		**3,310**	**3,005**	**35**	**144**	**16**
Ontario		**14,105**	**10,780**	**34**	**811**	**25**
Saskatchewan		**14,395**	**4,525**	**32**	**757**	**59**
Canada-wide		**59,930**	**35,090**	**33**	**3,011**	**29**

[a] Includes an estimation for the unit Genesee 3 that was not yet commissioned in 2001.
[b] Estimation. No value available for this EGU.
[c] Main fuel is sub-bituminous coal, although a large quantity (>15%) of petroleum coke was used in 2002.
[d] Data not available. Estimation based on high mercury concentration in coal (75 ppbw).
[e] Mixture of sub-bituminous and bituminous coals is used. A ratio of 70:30 is applied in calculations.
[f] Mixture of lignite and sub-bituminous coals is used. A ratio of 75:25 is applied in calculations.

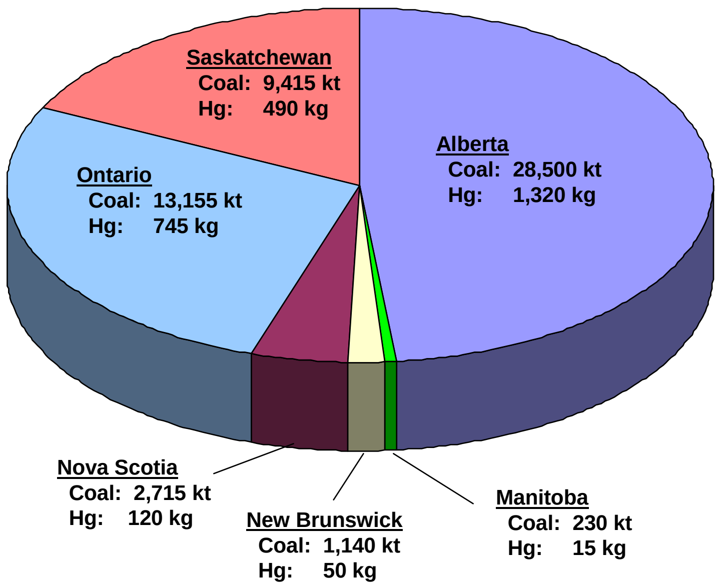

Figure 2-2: Provincial coal utilization and estimated total mercury input in 2007

Coal-fired EGUs in Canada use a variety of sub-bituminous, bituminous and lignite coal (Fig. 2-3). Several were built in and around coal mines while others need to import from abroad (Nova Scotia Power EGUs; Brandon, Lambton, Nanticoke, Thunder Bay and Belledune EGUs). Coal situation is different in each province.

- In Alberta, most EGUs use sub-bituminous coal almost exclusively from local mines. It contains high moisture (15–25% by weight) with a high heating value of 18–20 MJ/kg as received and a mercury content oscillating between 30–75 ppb wet on average.

- SaskPower EGUs exploit mine-mouth low rank lignite. This coal has very high moisture content (> 30%wt) and low heating value (HHV = 8–11 MJ/kg wet). According to the CEA mercury program, it contains 50 ppb wet of mercury in average.

- The Brandon facility in Manitoba uses imported sub-bituminous coal from the Powder River Basin (PRB) in Montana that has a good heating potential (26 MJ/kg) but a relatively high mercury content (70 ppb on wet basis).

- Nova Scotia Power EGUs import most of its bituminous coal from the U.S. and South America. The heating value is 26–30 MJ/kg wet and has relatively low mercury content (< 45 ppb wet). They also use petroleum coke and heavy oil as secondary fuels except for the Point Aconi facility that uses petroleum coke as the primary fuel in their circulating fluidized bed boiler. In fact, they use a coke–to–coal ratio of 80:20. This blend results in low mercury input.

- The New Brunswick Belledune facility uses imported bituminous coal with heat content and mercury content similar to the one used by Nova Scotia Power EGUs.

- Ontario Power Generation purchases its coal from the U.S. and Western Canada. Lignite coal (Thunder Bay, Atikokan) is obtained from Saskatchewan and sub-bituminous coal (Thunder Bay, Nanticoke) from the Powder River Basin in Montana. Bituminous coal (Lambton, Nanticoke) is obtained from Eastern U.S.

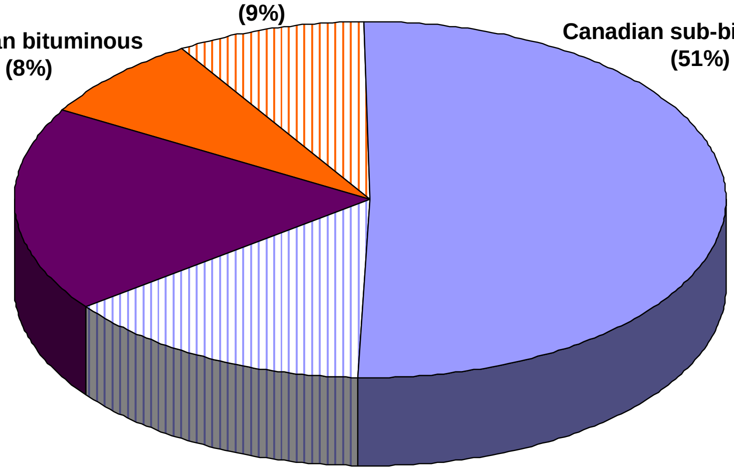

Figure 2-3: Ranks of coal combusted by Canadian coal-fired EGUs in 2007[12]

2.1.2.2 Petroleum products

Petroleum products like natural gas, diesel and light/heavy fuel oil are also used in Canada to produce steam. In 2007, electric power generation using theses fuels attained 44.3 TWh_e, corresponding to about 40% of electricity production by coal-fired EGUs. The bulk was obtained from natural gas combustion (37.6 TWh_e).[13]

Like coal, mercury in crude oil and condensates are volatized during combustion. Reported total mercury concentrations in liquid hydrocarbons vary considerably by region. For example, gas condensates in Southeast Asia have dissolved total mercury concentrations up to 900 ppb with an average of 200 ppb or so.[14] In contrast, most crude oils processed in the U.S. and Canada contains less than 10 ppb of mercury. In Canada, the average is about 2.1 ppb. Mercury in refined products including gasoline, diesel, kerosene, light distillates and utility fuel oil was also reported elsewhere to extend between traces and 3 ppb at most.[15] To give an idea, assuming a 3 ppb concentration, annual mercury input in Canadian EGUs fired by petroleum products would approach 5 kilograms per year for liquid hydrocarbons and 25 kilograms for natural gas. Altogether, this figure is less than 1 percent of mercury input in coal-fired EGUs. Most of the mercury in crude oils and natural gas is elemental with traces of mercuric species (Hg^{2+}).

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[12] Statistics Canada, Electric power generation, transmission and distribution report, 2007.
[13] Ibid.
[14] U.S. EPA, Mercury in petroleum and natural gas: estimation of emissions from production, processing and combustion (EPA-600/R-01-066), 2001.
[15] Wilhelm, M.S. et al., Mercury in crude oil processed in the United States (2004), Environmental Science & Technology, 41 (13), 2007, p. 4509.

2.1.3 Air pollution control

Emissions from fuel combustion can be significant especially for coal. Besides mercury, sulphur oxides (SO_X), nitrogen oxides (NO_X) and particulate matter (PM) are other criteria pollutants crucial for this sector. In fact, EGUs account for about 25% of SO_X and 10% of NO_X industrial emissions in Canada. Corresponding mercury emissions account for 35% of industrial emissions.[16] Air quality legislations are therefore pushing the EGUs to consider the installation of air pollution control (APC) technologies that are capable to reduce the emission of one or several criteria pollutants.

2.1.3.1 Particulate matter control

Particulate matter emission reduction technologies include mechanical collectors (i.e. cyclone), fabric filters (FF), electrostatic precipitators (ESP) and wet scrubbers. Most Canadian coal-fired EGUs are operating dry cold-side ESPs with exceptions using a dry hot-side ESP or a fabric filter (Tab. 2-4).

Different ESP configurations apply a high-voltage electric field for the migration of particulate matter on grounded collecting plates. ESPs have high removal potential for all particulate sizes including the very fine as long as the particulate resistivity is not excessive (i.e. poor conductor). Previous results have shown that the native mercury removal by cold-side ESPs is moderate within the 10–40% bracket for bituminous and sub-bituminous coal combustion.[17,18] This figure falls drastically (<10%) for lignite coal with its significant moisture content.[19] In this case, it is preferable to operate ESPs at higher temperature so to prevent water condensation. Particulate-bound mercury is essentially inexistent at high temperature (250–400°C) which explains the slight mercury removal rate by hot-side ESPs (< 5%).[20]

Besides temperature, several factors like carbon content in fly ash and chlorine/sulphur content in coal were revealed to influence the extent of mercury control by CS-ESP.[21] Loss of ignition carbon in the ash, more prominent in bituminous coal, chemically adsorbs oxidized mercury which accounts for the larger mercury capture rate for bituminous coal compared to other coal ranks. Chlorine meanwhile is responsible for the oxidation of Hg^0 into Hg^{2+} species which, in turn, is more readily adsorbed on fly ash surface. In contrast, sulphur leading to sulphur oxides promotes the reduction of Hg^{2+} into Hg^0. Altogether, low flue gas temperatures, significant chlorine and carbon content and low sulphur content in coal is expected to improve co-reduction of mercury by CS-ESP.

Fabric filters also known as baghouses are designed to capture particulate emissions using tightly woven tubular bags through which dusty gas flows from the inside to the outside. This technology was shown to remove significant fractions of total mercury emissions (> 50%) owing

[16] Environment Canada, Criteria air contaminants and related pollutants website.
[17] U.S. EPA, Mercury study report to congress (Volume 2): An inventory of anthropogenic mercury emissions in the United States (EPA-452/R-97-004), December 1997.
[18] Pavlish J. H. et al., Status review of mercury control options for coal-fired power plants, Fuel Processing Technology, 82, 2003, p. 89.
[19] Sjostrom, S. et al., Analysis of key parameters impacting mercury control on coal-fired boilers, ADA Environmental Solutions Publication # 03008, September 2003.
[20] Pavlish J. H. et al., Status review of mercury control options for coal-fired power plants, Fuel Processing Technology, 82, 2003, p. 89.
[21] Ibid.

to the oxidation of Hg^0 and subsequent capture of Hg^{2+} species occurring because of excellent gas-solid contact across the fly ash cake.[22,23] Like for ESPs, high chorine content and low temperatures are required to maximize inlet Hg^0 oxidation and Hg^{2+} capture. Good mercury removal is expected for bituminous and sub-bituminous coal combustion (Hg^0: 40–80%; Hg^{2+}: 20–50%).[24] However, for plants burning lignite coal, much lower mercury removal is obtained likely due to the high fabric filter operating temperature (>180 °C) typical for these plants.[25] Generally, fabric filter offers the highest native mercury removal potential of all PM control system.

Other available PM control technologies like mechanical collectors and wet particulate scrubbing are not relevant to the Canadian coal-fired EGU sector (except for the multi-cyclone installed as a pre-deduster at H.R. Milner's facility). Anyway, these technologies are not recognized to sequester mercury emissions at significant levels.

2.1.3.2 SO_X control

Flue gas desulphurization (FGD) technologies include wet, semi-dry and dry scrubbing approaches. In wet FGD systems, the flue gas is sprayed with an aqueous solution containing lime or limestone which reacts with SO_2 to form recoverable calcium sulphite/sulphate precipitates (gypsum). In contrast to water-spray particulate scrubbers, this method has the potential to remove extra mercury emissions considering that some ionic mercury species can form mercury salts in these conditions. Previous results have shown that Hg^{2+} is removed by over 80% while Hg^0 emissions are barely controlled notwithstanding the coal rank.[26] The extent of mercury removal is therefore related to the inlet Hg^{2+}/Hg^0 ratio. In some cases, the Hg^0 output was even greater than the input possibly due to chemical reduction of Hg^{2+} into Hg^0. Total mercury capture can therefore be improved by adding a chemical oxidizer to the FGD solution.[27] Two Canadian coal-fired EGUs are operating wet FGD scrubbers (two at Lambton and one at Belledune).

In semi-dry processes, an alkaline (i.e. calcium hydroxide) slurry is finely atomized into a dedicated absorber tower to neutralize SO_2 emissions from hot flue gas. This system is equipped with a PM control system removing fly ash particulates and dried sorbent residues generated by the spray dryer. According to studies, it has the potential to remove more Hg^0 (typically 20–40 %) than wet scrubbing processes. Hg^{2+} removal stays moderate (typically 20–60 %).[28] The use of a fabric filter for PM control was shown to provide better total mercury

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[22] Pavlish J. H. et al., Status review of mercury control options for coal-fired power plants, Fuel Processing Technology, 82, 2003, p. 89.
[23] Sjostrom, S. et al., Analysis of key parameters impacting mercury control on coal-fired boilers, ADA Environmental Solutions Publication # 03008, September 2003.
[24] SENES Consultants Ltd., Evaluation of technologies for reducing mercury emissions from the electric power generation sector, prepared for the CCME, February 2002.
[25] Sjostrom, S. et al., Analysis of key parameters impacting mercury control on coal-fired boilers, ADA Environmental Solutions Publication # 03008, September 2003.
[26] SENES Consultants Ltd., Evaluation of technologies for reducing mercury emissions from the electric power generation sector, prepared for the CCME, February 2002.
[27] Pavlish J. H. et al., Status review of mercury control options for coal-fired power plants, Fuel Processing Technology, 82, 2003, p. 89.
[28] SENES Consultants Ltd., Evaluation of technologies for reducing mercury emissions from the electric power generation sector, prepared for the CCME, February 2002.

removal potential than ESPs as long as the chlorine content is significant.[29] Currently, one unit in Canada (Genesee facility) operates a lime spray drying process combined with a fabric filter to control SO_2 emissions and particulate matter.

Dry FGD processes consist of injecting a dry sorbent such as hydrated lime or activated carbon directly in the flue gas to absorb SO_2 emissions. Like semi-dry FGD systems, the installation of a PM control equipment (typically fabric filter) is required downstream. Incidental mercury removal (typically >50%) occurs mainly through the adsorption of Hg^{2+} species onto particles.[30] The sorbent nature and loading will determine the level of mercury control. Shand facility in Saskatchewan operates a LIFAC process, a dry FGD process where limestone is directly injected into the boiler to form quick lime. Following the air pre-heater, the flue gas passes through a water injection system to activate the quick lime reactivity towards SO_2.

2.1.3.3 NO_X control

Preventive or post-combustion measures can be considered for the reduction of nitrogen oxides (NO_X) emissions. Prevention of NO_X emissions at the source can be done by optimizing the burner design for best aerodynamic distribution of air and fuel (low-NO_x burner, LNB), controlling the flame stoichiometry by regulating the overall fuel/air ratio, or staging the combustion process (i.e. overfire air ports, OFA). These measures are intended to curb NO_X emissions but do not affect the overall mercury emissions exiting the boiler. It could however modify mercury speciation in the flue gas that would possibly influence post-combustion controls performance on that respect. Several Canadian coal-fired EGUs use preventive measures to control NO_X (see Tab. 2-4).

Post-combustion NO_X removal includes selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR) processes. In both cases, it involves the vaporization of a reducing agent, typically ammonia, into the flue gas reacting with the NO_X to form nitrogen and water vapour. For SNCR processes, the reaction is carried out at 900–1100°C within the boiler super heater and convective heat transfer regions. For SCR processes, the reaction is carried out at 300–400°C in presence of oxygen and a reduction catalyst following the heat transfer region. There has been growing evidence that SCR catalyst provides good conditions for the oxidation of Hg^0 into Hg^{2+}. In fact, studies have shown that SCR increases Hg^{2+} content in the flue gas by 35% for bituminous and sub-bituminous coal combustion.[31] Special Hg^0 oxidation catalysts to be placed after SCR catalysts were even developed recently. This de-NO_X technology is however not designed to sequester mercury vapours. Installation of another control system downstream must be added to recover the oxidized mercury. With the SCR–wet FGD configuration, total mercury capture may exceed 80%.[32] Currently, there are two Canadian coal-fired EGUs operating SCR processes (Tab. 2-4). No SNCR processes are in operation.

[29] Pavlish J. H. et al., Status review of mercury control options for coal-fired power plants, Fuel Processing Technology, 82, 2003, p. 89.
[30] SENES Consultants Ltd., Evaluation of technologies for reducing mercury emissions from the electric power generation sector, prepared for the CCME, February 2002.
[31] Ibid.
[32] Ibid.

2.1.3.4 Mercury control

Some pre-combustion and post-combustion systems specific to mercury removal are available nowadays. Regarding prevention, coal switching and coal cleaning are possibilities. Switching for coal with lower mercury content is however an unlikely solution given that power plants are usually located next to the coal mine. In this case, mercury reduction would be roughly equivalent to the difference in mercury content between coal deposits. Besides, a switch would not decrease mercury emissions sizeably unless a naturally low Hg coal deposit is easily available.

The main objective of installing a pre-combustion coal cleaning system is to remove large amounts of non-combustible material in coal and thus, increase its heat value and reduce post-combustion pollution. Conventional cleaning equipment includes heavy media separators (i.e. cyclones), pulse water separators, constant velocity separators and froth flotation cells. Wet coal is then dewatered (i.e. vacuum filters, centrifugal dryers, etc.) prior to combustion. In the process, coal cleaning will remove a fraction of mercury to an extent that varies widely (0–80%) depending on the coal deposit. Data from literature have shown that conventional coal cleaning can remove in average 35–40% of mercury from coal.[33] Such a wide range of results from washing suggests different modes of mercury occurrences in coal. A study determined that mercury in most North American bituminous coal is clustered in pyrite which is more readily washed out. Meanwhile, the proportion of mercury present in organic parts of coal is more prominent in low-rank sub-bituminous and lignite coal.[34] Conventional coal cleaning for these coals would therefore result in more limited mercury removal.

Post-combustion technologies for mercury removal include activated carbon injection processes, wet scrubbers and several emerging processes that have been developed and tested but have not yet been deployed on a commercial scale. Considering wet scrubbing exclusively for mercury control is however unlikely since it would be cost prohibitive. It has been suggested instead to add chemical agents (i.e. chloric acid, sodium sulphide) in a wet FGD scrubber to boost the oxidation of Hg^0 into Hg^{2+} and then promote the absorption of Hg^{2+} in the wet FGD solution. With proper operation, total mercury removal would reach 80+%.

Presently, the most promising option for mercury removal is the activated carbon injection (ACI) process which is fundamentally similar to dry FGD processes. As implied, this technology consists of injecting activated carbon, impregnated carbon or any other sorbent into the gas stream at the air-heater outlet, upstream of a particulate control system (ESP, FF). In bonding with vapour phase mercury (Hg^0 and Hg^{2+}), activated carbon can provide good mercury removal efficiencies up to 80–98% if the conditions are appropriate (i.e. low temperature, high activated carbon loading, high chlorine content, low sulphur content).[35,36] Impregnated carbon with sulphur or iodine was shown to improve the absorption capacities resulting in better control but it comes at a price.[37]

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33 Toole-O'Neil, B. et al., Mercury concentration in coal: Unraveling the puzzle, Fuel, 78 (1), 1999, p. 47.

34 U.S. Department of the Interior, Mercury in U.S. coal – abundance, distribution and modes of occurrence (USGS fact sheet FS-095-01), September 2001.

35 Sjostrom, S. et al., Analysis of key parameters impacting mercury control on coal-fired boilers, ADA Environmental Solutions Publication # 03008, September 2003.

36 SENES Consultants Ltd., Evaluation of technologies for reducing mercury emissions from the electric power generation sector, prepared for the CCME, February 2002.

37 Ibid.

Prior to the CWS endorsed by the CCME in 2006, neither preventive nor post-combustion measures for mercury control were considered by Canadian coal-fired EGUs. Mercury control programs came forth in response to the CWS and latter, the Alberta regulation on mercury emissions from coal-fired power plants.[38] Among other issues, it required Albertan facilities to achieve a minimum mercury capture target of 70% of mercury in coal by January 2011. Since the inherent mercury capture by their conventional APC systems does not exceed 50% (Tab. 2-4), they were required to install additional means to improve mercury control. Here is the list of measures that were considered by Albertan coal-fired EGUs:

- TransAlta Corp.: The Sundance facility (unit 5) was the site of a short term (30 days) mercury control test in 2006 to evaluate the ability of achieving 70% mercury reduction using activated carbon injection and its effect on ESP performance. The Keephills facility (unit 2) was the site of a long-term pilot test (1 year) in 2007–2008 (August until Sept.) which involved the injection of different sorbents and feed rates.[39] This process has been continually refined since then. TransAlta had the intention to select the sorbent producing the most favourable results over an extended period of time and use it at their facilities by 2010. Implementation of a coal beneficiation process is also in the works at Keephills and Sundance power plants for the removal of rocks and dirt which will reduce the wear and tear of machinery.[40] The cleaning process is also expected to remove 20–35% of mercury from coal prior to combustion.

- Capital Power Corp.: In response to the regulation, they proposed to install a brominated activated carbon injection system preceding the ESP for the Genesee older units 1 and 2.[41] Combustion optimization was also proposed to improve overall mercury control. A full-scale ACI demonstration was run in 2008 (July–September) on the supercritical boiler (Genesee 3) which is already equipped with a semi-dry FGD scrubber and a baghouse. Under the plan, site-wide permanent installation of the equipment was to be completed by early 2010.[42]

- ATCO Power Ltd: The Battle River facility (unit 5) was the site of a full scale test on a brominated activated carbon injection system preceding the ESP.[43]

- Maxim Power Corp.: According to the company, the facility (H.R. Milner) is already in compliance with the regulation and should remain so through the end of its design life of 2012. An expansion project commissioning a 500 MW boiler is in the works. They plan to incorporate advanced emission control systems including activated carbon injection for mercury control.[44]

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[38] Alberta Environment, Environmental Protection and Enhancement Act – Mercury emissions from coal-fired power plants regulation, Alberta Regulation 34/2006.
[39] Canadian Electricity Association, Canada-wide standard for mercury emissions from coal-fired electric power generation plants, progress report 2008, personal communication.
[40] TransAlta Corp., TransAlta and the environment 2008 report on sustainability, 2008.
[41] Alberta Environment, The new mercury emission from coal-fired power plants regulation (March 2006), Alberta Environment Conference, April 2008.
[42] Capital Power Corporation, Genesee station connection newsletter, February 2009.
[43] Alberta Environment, The new mercury emission from coal-fired power plants regulation (March 2006), Alberta Environment Conference, April 2008.
[44] Maxim Power Corp., H.R. Milner, Alberta website.

Table 2-4: Conventional pollution control systems installed at Canadian coal-fired EGUs and their annual mercury emissions reported in the NPRI.

EGU	Unit #	PM control			SO_2 control			NO_X control		Reported mercury emissions (kg/a) [a]	Inherent mercury control (%) [b]
		CS-ESP	HS-ESP	FF	Wet FGD	Semi-dry FGD	Dry FGD	LNB/OFA	SCR		
Sundance	1–6	√								315 [c]	38
Keephills	1–2	√								113 [c]	14
Wabamun	4		√							50	54
Genesee	1–2	√								142	22
	3			√		√		√			
Sheerness	1–2	√								99	40
Battle River	3–5	√								91 [c]	6
H.R. Milner	1			√ [d]						5	72
Brandon	5	√								11	40
Belledune	2	√			√			√		18	70
Grand Lake	8	√								75 [c]	N/A [e]
Lingan	1–4	√						√		80	~0
Point Aconi	1			√						2	73
Point Tupper	2	√						√		22	~0
Trenton	5	√		√ [f]						44	5
	6	√						√			
Atikokan	1	√						√		32	15
Lambton	1–2	√						√		83	66
	3–4	√			√			√	√		
Nanticoke	1–6	√						√		140 [c]	71
	7–8	√						√	√		
Thunder Bay	2–3		√							37	27
Boundary Dam	1–6	√						√		286	11
Poplar River	1–2	√						√		269	15
Shand	1	√					√ [g]	√		100	8

[a] Average of mercury emissions reported in the NPRI between 2003–2008.
[b] Corresponds to (1 – average Hg emissions/Hg input) X 100%. Mercury input from coal based on 2002–2005 reports (CEA program, see Tab. 2-3).
[c] Reported 2008 mercury emission has dropped by at least 40% vs. the 2007 value.
[d] Includes a multi-cyclone separator before the fabric filter.
[e] Mercury in coal is unavailable.
[f] Under construction.
[g] LIFAC process.

In the last five years, SaskPower got involved in several research programs related to mercury control from lignite-fired power plants. Most notably, its Emission Control Research Facility located at Poplar River has been testing full-scale injection of enhanced activated carbon before and after the ESP at unit 2. The research program was intended to determine the optimum design for controlling mercury emissions coming from lignite combustion. Allowing the tests were conclusive, SaskPower was expected to install permanent systems at both Poplar River units and other lignite-coal burning plants by 2010. Both Poplar River units are operating an ACI system since June 2009.[45]

As part of their environmental plan, NS Power is aspiring to reduce their electricity production from coal-fired steam from 75% to less than 50% replacing it by non-emitting renewable sources. A 20% reduction is already observed between 2001 and 2007 coal consumptions. However, these reductions have actually little impact on overall mercury emissions. Hence, activated carbon injection systems have been installed at Point Tupper, Trenton and Lingan EGUs for further reductions to achieve the CWS Nova Scotia cap. They are actually in the process of troubleshooting technical difficulties.[46] The Point Aconi EGU with its already low annual mercury emission does not operate a mercury capture system.

No significant mercury control technologies are actually considered in Ontario, New Brunswick and Manitoba for the following reasons:

- Ontario: Four coal-fired units will be shut down by the end of 2010 and the remainder will be phased out by 2014.

- New Brunswick: The Grand Lake facility accounting for a large portion of total mercury emissions in New Brunswick (Tab. 2-4) will be shut down in 2010. It will enable the province to meet the mercury emission cap.

- Manitoba: The Brandon facility reports annual mercury emissions that are already within Manitoba's CWS 2010 cap. Besides, it is required by law to stop combusting coal to generate power since January 2010 except to support emergency operations.[47]

2.1.4 Reported mercury emissions

Mercury and its compounds that are released or disposed in air, water and land must be reported to the National Pollutant Release Inventory (NPRI) by facilities that emit over 5 kilograms annually. All coal-fired EGUs have declared mercury emissions recently.[48] The procedures used by EGUs to calculate the annual mercury releases are however not directly reported. Another source of information is the 2003 UDCP related to the CEA mercury program that collected data on mercury in coal, coal combustion residues and flue gas on the span of 3 years (2002–2005). Quality-assured sampling and analysis results are available on the CEA website.[49]

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[45] Canadian Electricity Association, Canada-wide standard for mercury emissions from coal-fired electric power generation plants, progress report 2008, personal communication.
[46] Nova Scotia Environment, personal communication, June 2010.
[47] Government of Manitoba, The climate change and emissions reductions act, 2008.
[48] Environment Canada, National Pollutant Release Inventory (NPRI).
[49] Canadian Electricity Association, Mercury information clearinghouse – Quarter 9: Mercury information clearinghouse final report, December 2005.

2.1.4.1 Air

Average total mercury releases in the atmosphere as reported in the NPRI for the last 5 available years are presented in Table 2-4. Most reported values per coal-fired EGU remained consistent throughout the years resulting yet to a slight consistent decrease Canada wide (Fig. 2-4). Significant reductions were however noted in 2008 for a number of facilities including the Sundance, Keephills and Battle River EGUs in Alberta. They reported mercury emissions that are at least 40% lower than 2007 emissions which should be accounted, at least partially, by the progressive installation of ACI mercury control systems. The Genesee and Sheerness EGUs have also seen their emissions decreased slightly in 2008. The Lambton, Nanticoke and Grand Lake facilities also registered sizeable reductions in their annual mercury emissions. For Nanticoke, the reduction was said to be caused by a decrease in mercury concentration in sub-bituminous coal.[50] According to 2008 inventory, the provincial CWS 2010 cap has been attained for Alberta and Manitoba. Saskatchewan remained the largest emitter in 2008 with a specific rate of 51 kg Hg per TWh_e (Fig. 2-5). Ontario has no specific CWS cap but is expected to help meet the Canadian CWS of 60% by 2010.

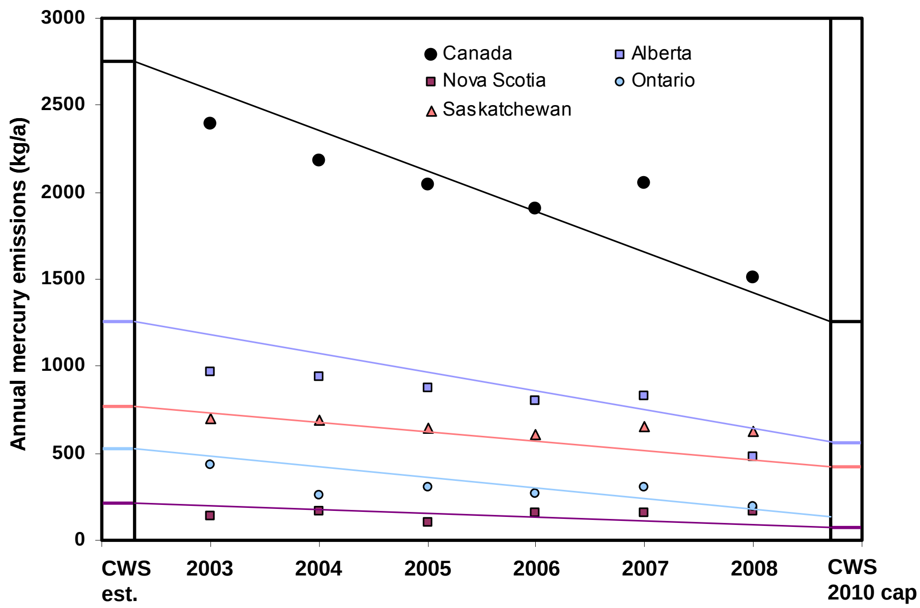

Figure 2-4: Recent annual trend on mercury emissions reported by Canadian coal-fired EGUs (New Brunswick and Manitoba are omitted)

[50] Canadian Electricity Association, Canada-wide standard for mercury emissions from coal-fired electric power generation plants, progress report 2008, personal communication.

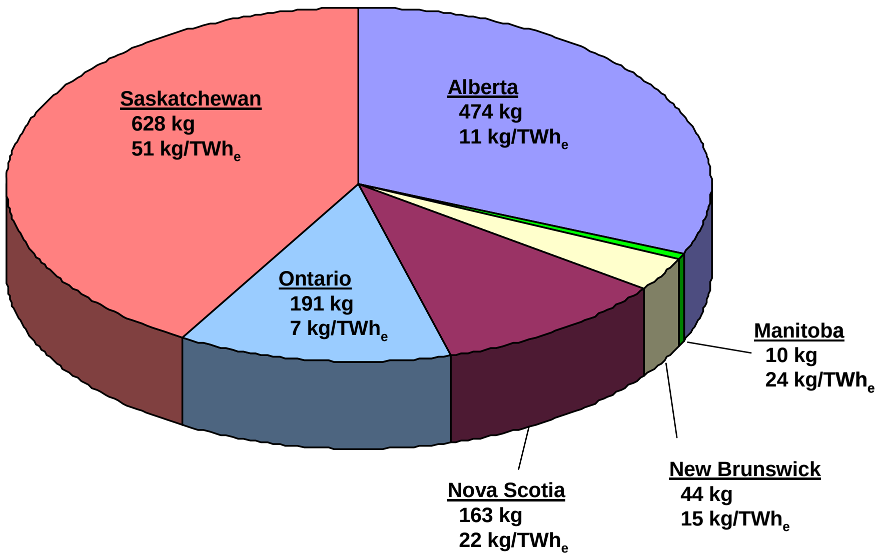

Figure 2-5: Reported 2008 mercury emissions by province and corresponding emission rate based on 2007 electricity generation

2.1.4.2 Soil and water media

Few Canadian coal-fired EGUs did report in the NPRI on-site mercury releases in water streams (Tab. 2-5) with values that are clearly minimal (< 5%) compared to mercury releases in the atmosphere (see Tab. 2-4). No mercury discharges on nearby land were reported either. Instead, most facilities reported mercury transfers via coal combustion residues (fly ash, bottom ash) whether they are disposed on-site, off-site or recycled in other products. Variation between annual values for the last 5 years is sizeable in some cases (Tab. 2-5) but the magnitudes remain roughly comparable with the results from the CEA mercury program back in 2002–2004.[51]

[51] Canadian Electricity Association, CEA mercury program, (www.ceamercuryprogram.ca/EN/mercury_home.html).

Table 2-5 : Mercury release in water streams and mercury transfer in coal combustion residues as reported in the NPRI between 2004 and 2008

EGU	Mercury releases in water (kg)	Mercury transfer in coal combustion residues (kg) [a]	CEA mercury program analysis – annual Hg output (kg) [b]
Sundance	6.2 ± 4.2	69.4 ± 42.1	215
Keephills		154.2 ± 161.4	55
Wabamun	0.9 ± 1.2	9.1 ± 11.7	50
Genesee	0.1 ± 0.2	47.6 ± 21.1	80
Sheerness		37.6 ± 2.3	65
Battle River		20.4 ± 2.1	35
H.R. Milner		23.4 ± 7.0	5
Brandon		1.1 ± 0.6	2
Belledune		21.9 ± 14.5	6
Grand Lake		1.4 ± 0.5	1
Lingan		8.9 ± 8.0	3
Point Aconi		14.9 ± 9.3	2
Point Tupper		2.9 ± 2.0	~0
Trenton		3.7 ± 3.3	6
Atikokan		0.5 ± 0.4	1
Lambton	0.006 ± 0.004	95.2 ± 12.7	95
Nanticoke	3.2 ± 0.5	160.4 ± 80.4	285
Thunder Bay		0.7 ± 0.4	~0
Boundary Dam			35
Poplar River			30
Shand			8

[a] Average and standard deviation of reported values for mercury that is disposed (on-site, off-site) and recycled by the EGUs between 2004 and 2008.
[b] Annual transfer of mercury in coal ash according to the results from the CEA mercury program.

2.2 Low mass emitters

Low-mass mercury emitters (LME) are units that release relatively small quantities of mercury. According to the CCME CWS monitoring protocol, the LME threshold for Canadian coal-fired EGUs had been fixed at:[52]

- 10 kg/a of mercury per stack for facilities with multiple stacks; or
- 20 kg/a of mercury per stack for facilities with one stack.

[52] Canadian Council of Ministers of the Environment, Monitoring protocol in support of the Canada-wide standards for mercury emissions from coal-fired electric power generation plants, July 2007.

According to the protocol, a facility would become eligible to operate an optional mercury monitoring regime for an upcoming calendar year if the annual stack emissions from established data for the previous three years fall within the LME category. Beginning in 2013, the LME monitoring option can be considered based on the plant's monitoring results generated during the previous calendar year.

Five facilities and corresponding stacks can be classified as low-mass emitters according to the latest reported mercury emissions in 2008 (Tab. 2-6). Others draw near the LME threshold (Keephills, Point Tupper and Lambton) while the remaining are considered, as of 2008, 'normal' mercury emitters.

Table 2-6: Assessment of latest reported annual mercury emissions by facilities with the CWS LME threshold.

Facility	NPRI 2008 mercury emission (kg)/# of stacks (LME?)	Facility	NPRI 2008 mercury emission (kg)/# of stacks (LME?)
Sundance	145/3 (no)	Point Aconi	3/1 (yes)
Keephills	22/1 (near threshold)	Point Tupper	24/1 (near threshold)
Wabamun	41/1 (no)	Trenton	41/2 (no)
Genesee	105/2 (no)	Atikokan	18/1 (yes)
Sheerness	90/1 (no)	Lambton	58/3 (near threshold for 2 stacks)
Battle River	67/2 (no)	Nanticoke	84/4 (no)
H.R. Milner	4/1 (yes)	Thunder Bay	31/1 (no)
Brandon	10/1 (yes)	Boundary Dam	285/5 (no)
Belledune	11/1 (yes)	Poplar River	244/2 (no)
Grand Lake	33/1 (no)	Shand	99/1 (no)
Lingan	95/2 (no)		

2.3 Peaking units

Peaking units are generally defined as electric generating units that operate only during the peak energy demand. They typically operate for less than 500 hours per year (< 5% of time). As of 2010, this definition of peaking units applies to the Brandon coal-fired unit in Manitoba which, by law, is required to use coal to generate power only to support emergencies such as times of drought. Other boilers that will be decommissioned shortly are not expected to be set aside for peak energy demand using coal fuel.

2.4 Hypothetical future coal-fired utilities

New coal-fired EGUs could be erected in the near future making use of combustion technologies (i.e. integrated gasification combined cycle, supercritical steam cycle technology) that are generally more energy- and environment-efficient than conventional pulverized coal combustion. As part of this study, Environment Canada has defined four hypothetical future units representing potential designs that could be considered by electric utility companies in Alberta and Saskatchewan (Tab. 2-7). Local sub-bituminous and lignite coal would be used. Every boiler has a nameplate capacity of 500 MW_e and an annual production of 3.5 TWh_e (80% annual operation). Each hypothetical unit considers particulate, SO_2 and NO_X control measures. Mercury control measures (activated carbon bed, activated carbon injection) are also considered which should provide a mercury control of at least 90%. In these conditions, the units' mercury emissions would fall within the LME category. The resulting emission rates would also comply with the CWS for new facilities.

Table 2-7: Four hypothetical, new Canadian coal-fired EGUs

Province	System description	Fuel description	Mercury
Alberta	Combustion: integrated gasification combined cycle Mercury control: activated carbon bed	**sub-bituminous** HHV: 24 MJ/kg wet Qty: 1,175 kt/a	input: 63 kg/a output: 6 kg/a **(1.8 kg/TWh_e)**
Saskatchewan	Combustion: super-critical Mercury control: activated carbon injection	**lignite** HHV: 16 MJ/kg wet Qty: 2,260 kt/a	input: 121 kg/a output: 12 kg/a **(3.4 kg/TWh_e)**
Alberta	Combustion: super-critical Mercury control: none	**sub-bituminous** HHV: 24 MJ/kg wet Qty: 1,510 kt/a	input: 81 kg/a output: 8 kg/a **(2.3 kg/TWh_e)**
Alberta	Combustion: in situ gasification Mercury control: activated carbon injection	**sub-bituminous** HHV: 24 MJ/kg wet Qty: 2,110 kt/a	input: 113 kg/a output: 11 kg/a **(3.2 kg/TWh_e)**

3. CURRENT MERCURY MONITORING TECHNIQUES

This section provides a performance assessment of currently available mercury monitoring techniques applicable to air emissions and coal-fired EGUs. Liquid and solid media mercury monitoring will be covered as well. Recommendations on best monitoring regimes and their supporting equipment will then be advanced based on specific criteria. Two monitoring regimes that would be suitable for low emitting facilities and peaking units will be proposed as alternatives. To provide some perspective on current work, a summary of known worldwide standards and targets on mercury emissions applicable to coal-fired EGU operation will introduce this section.

3.1 Approach

Regulations and guidelines pertaining to airborne mercury emissions established by the Canadian, U.S. and European authorities will be addressed and discussed based, among others, on the following records:

- Canadian Council of Ministers of the Environment, Canada-wide standards for mercury emissions from coal-fired electric power generation plants, October 2006.
- Canadian Council of Ministers of the Environment, Monitoring protocol in support of the Canada-wide standards for mercury emissions from coal-fired electric power generation plants, July 2007.
- Alberta Environment, Environmental Protection and Enhancement Act, Mercury emissions from coal-fired power plants regulation (Alberta Regulation 34/2006), 2006.
- U.S. EPA, Proposed national emission standards for hazardous air pollutants; and in the alternative, proposed standards of performance for new and existing stationary sources: electric utility steam generating units; proposed rule (40 CFR 60 and 63), January 2004.
- U.S. EPA, Standards of performance for new and existing stationary sources: electric utility steam generating units; final rule (40 CFR Part 60, 72 and 75), May 2005.
- Canadian Electricity Association, Mercury information clearinghouse – Quarter 7: Mercury regulations in the United States: Federal and State, July 2005.
- U.S. National Association of Clean Air Agencies, State/Local mercury/toxics program for utilities, April 2010.
- United Nations Economic Commission for Europe, The 1998 Aarhus Protocol on Heavy Metals, June 1998.
- European Union, Council Directive 96/62/EC of 27 September 1996 on ambient air quality framework and management, September 1996.
- European Union, Directive 2001/80/EC of the European Parliament and of the Council of 23 October 2001 on the limitation of emissions of certain pollutants into the air from large combustion plants, October 2001.
- European Union, Directive 2004/107/EC of the European Parliament and of the Council of 15 December 2004 relating to arsenic, cadmium, mercury and polycyclic aromatic hydrocarbons in ambient air, December 2004.
- Various U.S. states regulations on mercury emissions from coal-fired EGUs

Mercury monitoring methods will be described and assessed individually according to the following criteria: accuracy and uncertainties, measurement frequency, detection limit, reliability, practicality and extent of application, advantages, limitations and costs. Every aspect will be described qualitatively except for the costs that will be *roughly estimated* at this point. More relevant cost estimates will be provided in Section 5. Mercury monitoring methods considered by Canadian EGUs will be exposed at the end of this sub-section.

Basis of recommendation for the best mercury monitoring regime and alternative regimes for low-mass emitters and peaking units will be defined. Recommended regimes will be described broadly since most commercial systems have different specifications. Recent documents from national and international organizations were consulted for the assessment of mercury monitoring regimes. It includes the following sources:

- Canadian Council of Ministers of the Environment, Monitoring protocol in support of the Canada-wide standards for mercury emissions from coal-fired electric power generation plants, July 2007.
- Mazzi, E. et al., Canada wide standards mercury measurement methodologies for coal-fired power plants, EPRI-EPA-DOE-AW&MA Symposium paper #15, August 2006, Baltimore, Maryland, USA.
- Electric Power Research Institute, Continuous mercury monitoring guidelines, March 2007.
- Asia-Pacific Economic Cooperation, Best practices in environmental monitoring for coal-fired power plants: Lessons for developing Asian APEC economies, APEC Energy Working Group Project EWG 06/2007, November 2008.
- Lehigh University Energy Research Center, Armstrong Project: Evaluation and comparison of U.S. and EU reference methods for measurement of mercury, heavy metals, $PM_{2.5}$ and PM_{10} emissions from fossil-fired power plants, February 2007.
- Australian Government – Department of the Environment, Water, Heritage and the Arts, Emission estimation technique manual for fossil fuel electric power generation, V2.4, March 2005.
- European Committee of Standardization, EN 13211:2001 – Air quality: Stationary source emissions. Manual method of determination of the concentration of total mercury, August 2001.
- European Committee of Standardization, EN 14884:2005 – Air quality: Stationary source emissions. Determination of total mercury: automated measure systems, December 2005.
- Canadian Electricity Association, Mercury information clearinghouse – Quarter 2: Mercury measurement, April 2004.
- Canadian Electricity Association, Mercury information clearinghouse – Quarter 8: Commercialization aspects of sorbent injection technologies in Canada, October 2005.
- Canadian Electricity Association, CEA Mercury Program – Sampling & analysis implementation plan – Plan development template, July 2002.
- U.S. EPA, Standards of performance for new and existing stationary sources: electric utility steam generating units; final rule (40 CFR Part 60, 72 and 75), May 2005.

3.2 Current regulations on mercury emissions

North American jurisdictions have started to develop strategies and standards on mercury emissions from the utility section in the last ten years or so in recognition of the significant hazards it poses on public health. Case in point, Canada has signed a number of regional and international agreements with the United States and the United Nations Economic Commission for Europe to reduce mercury emissions. It has resulted in a national consensus on terms of a Canada-Wide Standard for coal-fired EGUs.

3.2.1 Canada

Mercury and its compounds must be reported to the NPRI by the coal-fired EGUs that emit over 5 kilograms annually. This is applicable to all Canadian facilities (see Section 2.1.4) except the Point Aconi facility which has reported their mercury emissions nevertheless. The procedures applied by the facilities to obtain the annual mercury releases are however unknown.

The Canadian and provincial governments under the CCME have entered the CWS agreement in 2006 targeting provincial mercury caps by 2010 and mercury capture rates for new plants.[53] As stated in the agreement, the coal-fired EGU sector has emitted 2,695 kilograms of mercury in 2003 from an estimated 3,725 kilograms of mercury in coal burned. Over 70% of incoming mercury was released in the atmosphere while the remaining fraction was presumably captured in bottom ash and fly ash.

The CCME have set provincial targets (Tab. 3-1) for existing facilities representing a 60% improvement on mercury capture nationwide. Based on 2003–2005 mercury emission numbers, the target represents a 70% capture of mercury in burned coal. After reviewing progress reports, a second phase of the CWS may explore the capture of 80% of mercury from coal for 2018 and beyond. It would bring the total mercury emission rate at about 10 kg per terawatt-hour of electricity (based on 2003 production for Canadian EGUs excluding Ontario).

Under the CWS proposition, new coal-fired EGUs including a unit replacing an existing one with an equivalent technology will be subject to a more stringent mercury emission limit. According to the CWS, the mercury capture rate should reach 75% of total mercury contained in coal burned. The use of bituminous coal and blends requires a mercury capture rate of at least 85%.

Table 3-1: Provincial targets for annual mercury emissions from existing coal-fired EGUs as stated by the CWS

Province	Estimated emissions in 2002–2005 (kg/a)	2010 target (kg/a)	% reduction (2010 vs. 2003)	Emission rate for 2010 target (kg/TWh) [b]
Alberta	1,180	590	50	13.2
Saskatchewan	710	430	39	34.1
Manitoba	20	20	0	35.7
Ontario	495	n/a [a]	n/a	n/a
New Brunswick	140	25	82	5.7
Nova Scotia	150	65	57	7.0
Total	**2,695**	**1,130** [c]	**58** [c]	**10.8** [c]

[a] Coal-fired power generation will be phased out by 2014 in Ontario (Coal Closure Regulation 496/07). Four power plants are expected to be shut down in 2010 helping to meet the CWS of 60% capture of mercury by 2010.
[b] Electricity production for 2003 was obtained from the CCME UDCP (see Tab. 2-2).
[c] Does not include Ontario's target.

[53] Canadian Council of Ministers of the Environment, Canada-wide standards for mercury emissions from coal-fired electric power generation plants, October 2006.

The CCME has conjointly prepared a monitoring protocol in support to the CWS providing guidance to provincial jurisdictions on monitoring and reporting mercury emissions.[54] This protocol is intended to promote data consistency between facilities for effective management of mercury emissions. Accordingly, it recommended monitoring approaches in accordance with plant operation (i.e. normal emitters, low-mass emitters, peaking units). The short protocol has also provided groundwork for reporting, recordkeeping and QA/QC procedures.

In 2006, Alberta Environment adopted the recommendations from the Clean Air Strategic Alliance and published a regulation (AR 34/2006) regarding mercury emissions from coal-fired EGUs.[55] Specifically, it required the operators to submit plans for mercury reduction to Alberta Environment by March 2007. In this plan, a proposal for mercury control was to be submitted to achieve a minimum mercury capture target of 70% starting in January 2010. By the end of 2012, a proposal to improve mercury control up to the regulation objective of 80% is expected by Alberta Environment in order to achieve 80% capture by 2013. The regulation also requires on-going stack analysis and/or mass balance estimations (in accordance with the CCME CWS) until continuous emission monitoring systems (CEMS or an equivalent program) are operational by January 2011.

Other provincial jurisdictions affected by the CWS are expected to meet the targets including Ontario which is expected to shut down 4 coal-fired boilers in 2010. The remaining fleet will be phased out by 2014 leading to zero mercury emissions.

3.2.2 United States

During the 1990's, the United States Environmental Protection Agency (U.S. EPA) identified coal-fired boilers as the largest single category of atmospheric mercury emissions accounting to one-third of the anthropogenic emissions. While the overall mercury emissions from U.S. industries have dropped by 45% between 1990 and 2000, the EGU sector emissions have stagnated at around 50 tons per year (42% of industrial emissions).[56] The agency then proposed in 2004 the *Utility Mercury Reduction Rule* to cap and reduce mercury emissions from coal-fired EGUs.[57] They considered two reduction approaches: a direct control under the MACT standard of the Clean Air Act and a market-based cap and trade program. This rule was primarily intended to solicit comments on these approaches. A supplemental document was issued in 2004 which included a model to administer a mercury trading program as well as monitoring and reporting requirements for state jurisdictions.[58]

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[54] Canadian Council of Ministers of the Environment, Monitoring protocol in support of the Canada-wide standards for mercury emissions from coal-fired electric power generation plants, July 2007.

[55] Alberta Environment, Environmental Protection and Enhancement Act, Mercury emissions from coal-fired power plants regulation (Alberta Regulation 34/2006), 2006.

[56] U.S. EPA, Mercury study report to congress: Volume 2: An inventory of anthropogenic mercury emissions in the United States (EPA-452/R-97-004), December 1997.

[57] U.S. EPA, Proposed national emission standards for hazardous air pollutants; and in the alternative, proposed standards of performance for new and existing stationary sources: electric utility steam generating units; proposed rule (40 CFR 60 and 63), January 2004.

[58] U.S. EPA, Supplemental notice for the proposed national emission standards for hazardous air pollutants; and in the alternative, proposed standards of performance for new and existing stationary sources : electric utility steam generating units; proposed rule (40 CFR 60, 72 and 75), March 2004.

In March 2005, the U.S. EPA introduced the *Clean Air Mercury Rule* (CAMR) for electric utility steam generating units, which outlines a cap-and-trade system to reduce mercury emissions for existing facilities.[59] New facilities would have been subjected to new source performance standards (Tab. 3.2). However, this rule was vacated in 2008 by court orders because it was found to violate the Clean Air Act by not requiring implementation of the maximum achievable technology. A new CAMR is actually in the works at the federal level which intends to propose mercury standards for coal- and oil-fired electric generating facilities by March 2011.

The cap and trade program proposed in 2005 would have reduced nationwide utility emissions of mercury in two phases starting with a cap of 38 tons in 2010. This would have resulted in a 20% reduction compared to the annual U.S. mercury emissions (48 tons/a) compiled in 1997. This relatively small reduction rate was expected to follow suit with the separate but closely related Clean Air Interstate Rule (CAIR) proposed the same year addressing sulphur dioxide (SO_2) and nitrogen oxides (NO_X) emissions through the Acid Rain Trading Program.[60] Implementation or improvement of SO_2/NO_X control was expected to reduce mercury emissions enough to achieve the mandated 20% reduction target. The CAIR is also reviewed by the U.S. EPA since 2008 due to court orders. A second cap, substantially reducing mercury emissions up to 15 tons per year (69% reduction), would have been applied for 2018 pushing facilities to implement mercury control strategies by that time.

According to the CAMR, compliance with the final standards of performance for mercury is based on a 12-month rolling average. It would have required the operator to monitor Hg emissions continuously by installing and operating continuous emission monitoring system (CEMS) or any appropriate long-term method that can collect an uninterrupted sample of mercury in the flue gas. For units that had started commercial operation before July 2008, mercury monitoring systems was to be installed and certified by January 2009. The monitoring system should meet the requirements of the CAMR (40 CFR part 75). The rule would have required that valid mercury emissions data be obtained for a minimum of 75% of the unit operating hours each month. Otherwise, the data of the month would have been discarded and replaced by the mean mercury emission rate for the last 12 months. In subsequent occurrences, the maximum emission rate from the last 12 months would have been reported. When this occurs, the rolling average should be weighted according to the unit operating hours in that month.

According to the *Utility Mercury Reduction Rule*, the MACT standards proposed at the time would have established separate mercury emission limits for new and existing units subcategorized according to coal rank (Tab. 3-2). The operators of existing units would have had the option of complying with either the limit on thermal input basis (kg/TWh_{th}) or limit on electric production basis (kg/TWh_e). As a rule, the thermal efficiency of typical coal-fired EGUs was fixed at 33% (kW_e/kW_{th}). Meanwhile, new units would have been subjected to limits based on electrical production rate only. The initial standards proposed by the U.S. EPA in the *Utility Mercury Reduction Rule* were modified in the CAMR according to a refined analysis of documentation (Tab. 3-2). No standards were proposed for oil-fired and gas-fired EGUs regarding mercury emissions.

[59] U.S. EPA, Standards of performance for new and existing stationary sources: electric utility steam generating units; final rule (40 CFR 60, 72 and 75), May 2005.
[60] U.S. EPA, Rule to reduce interstate transport of fine particulate matter and ozone (clean air interstate rule); Revisions to acid rain program; Revisions to the NOx SIP call; Final rule (40 CFR 51, 72 et al.), May 2005.

Table 3-2 : Formerly proposed standards (12-month rolling average) by the U.S. EPA for coal-fired EGUs capable of firing more than 73 MW of coal and sell over 25 MW of electricity

Fuel/system type	Existing EGU		New EGU	
	Thermal basis (kg/TWh_{th}) [a]	Electric basis (kg/TWh_e) [a]	Electric output (kg/TWh_e) [a]	Electric output (kg/TWh_e) [b]
Bituminous coal (incl. anthracite)	3.1	9.5	2.7	9.5
Sub-bituminous coal	9.0	27.7	9.1	19.1/35.5 [c]
Lignite coal	14.2	44.5	28.1	65.8
Coal refuse	0.6	1.9	0.5	0.6
Integrated gasification combined cycle	29.4	90.7	9.1	9.1

[a] Values according to the *Utility Mercury Reduction Rule* (40 CFR 60 and 63), 2004.
[b] Values according to the *Clean Air Mercury Rule* (40 CFR 60, 72 and 75), 2005.
[c] The lower limit is targeted when a wet FGD (flue gas desulphurization) system is operational. The higher limit is the target when dry FGD is installed.

3.2.3 U.S. states

Under the Clean Air Amendments of 1990, each state is free to promulgate stricter emission regulations than are provided by the federal rule-making process. Although the CAMR is actually being reconsidered by the federal level, several states have imposed mercury emission limits or are in the process of consultation. Appendix A sums up the U.S. states strategies and regulation addressing mercury emissions from coal-fired EGUs according to a National Association of Clean Air Agencies (NACAA) census.[61]

Most legislation adopted by U.S. states imposes mercury emission targets that require a capture of at least 80% of inlet mercury or a specific emission rate in the range of 1–3 kg/TWh_{th} (or 3–9 kg/TWh_e). This is about two to three times more rigorous than federal targets for bituminous coal. Irrespective of power plants situation, Massachusetts has imposed up to date the most stringent emission rates (1.13 kg/TWh_e). In most regulated states, the final target will be effective in the next five years (2010–2015). However, considering the status of the CAMR, the majority of states have opted to wait for a new federal MACT.

Monitoring provisions for regulation compliance were developed conjointly with the states' emission limits or are under development replacing the vacated CAMR Part 75 provisions. For some states, key monitoring elements are provided below:

- Massachusetts: Any unit that combusts coal should have installed end-of-stack CEMS by January 2008. Prior to this date, other methods could have been used (triplicate measurements on a quarterly basis were required) to determine the validity of the emission limit (kg/TWh_e). Once the CEMS is installed, the facility must demonstrate every year that the mercury emissions from the previous calendar year calculated as a 12-month rolling average are in compliance with the state's regulation. Verification of the uncontrolled mercury removal efficiency limit (85%) is based on mercury CEMS emissions against the

[61] National Association of Clean Air Agencies, State/local mercury/toxics programs for utilities, April 2010.

average historic mercury inlet emissions (2001–2002) using a stack testing methodology approved by the authority.[62]

- Connecticut: Monitoring should be done in accordance with EPA Method 29 stack testing method, as amended from time to time or any other alternative method approved by the U.S. EPA. Stack testing should be conducted on a calendar quarter basis. Compliance of mercury emissions should be based on the average of the stack tests conducted during the two most recent calendar quarters.[63]

- New Jersey: Facilities can consider either the EPA Method 29 stack testing method (or an equivalent) or a CEMS, as long as it complies with the quality assurance requirements defined by federal specifications. The monitoring protocol shall be submitted each year for approval to the state's environmental department. For quarterly stack emission testing, the owner shall submit a copy of the results within 60 calendar days after completion. For compliance purpose, the owner shall report for the preceding year the annual weighted average mercury emissions of all valid stack emission tests performed for four consecutive quarters weighted by megawatt hours produced each quarter.[64] Verification of the uncontrolled mercury removal efficiency limit (90%) is based on the end-of-stack test results described above against stack test results conducted simultaneously for the gas stream at the inlet of the APC apparatus.

- New York: The rule adopts the federal requirements of the vacated CAMR (CEMS or sorbent traps). Each facility must install monitoring systems to monitor mercury mass emissions and individual unit heat input.[65]

- Delaware: Compliance with the emission limit (as kg/TWh_{th}) shall be demonstrated with a CEMS that is installed, calibrated, operated and certified in accordance with the CAMR requirements. For demonstration of compliance with the percentage capture of uncontrolled Hg emissions, the owner should have conducted at least four quarterly stack tests to measure the amount of mercury in the flue gas upstream of any pollution control device (baseline). Semi-annual reports including one-hour averages, daily mass emission and the calendar year-to-date summation of mass emissions are required.[66]

- Maryland: Compliance with the required mercury emission limit shall be demonstrated with a continuous emission monitoring system that is installed, operated, and certified in accordance with the CAMR requirements. The results should be reported as a 12-month rolling average weighted on heat input. In case the owner elects to demonstrate compliance on mercury reduction, a mercury flue gas baseline should be obtained by performing quarterly combustion gas tests on the uncontrolled mercury emissions in the flue gas prior to any APC system (incl. coal mercury beneficiation). The average of 6 stack tests over an 18-

[62] Massachusetts Department of Environmental Protection, Mercury emissions for power plants (310 CMR 7.29), May 2004.
[63] Connecticut Department of Environmental Protection, Connecticut General Statutes – Section 22a-199: Mercury emission standards, 2007.
[64] New Jersey Department of Environmental Protection Division of Air Quality, Air Pollution Code – Subchapter 27: Control and prohibition of mercury emissions, 2006.
[65] New York State Department of Environmental Conservation, New York Codes of Rules and Regulations – Part 246: Mercury reduction program for coal-fired electric utility steam generating units, 2006.
[66] State of Delaware, Natural Resources & Environmental Control: Air quality Management Section – Electric generation unit (EGU) multi-pollutant regulation, 2006.

month span should be applied as the baseline. Annual compliance reports are required by the legislation.[67]

- Michigan: An electricity generator with a nameplate capacity of more than 25 MW producing electricity for sale shall install, calibrate, maintain and operate a continuous monitoring system or a sorbent trap monitoring system for the measurement of mercury. Peaking units (<1 month of operation annually) are not required to conduct continuous monitoring. The unit may also be eligible to use an alternative monitoring regime if it demonstrates a low mercury mass emission. Demonstration shall be done according to a mercury stack testing method referred in the regulation (minimum of 3 runs at maximum routine load while firing coal with the highest mercury content). If the results do not exceed the LME threshold set by the regulation, then the owner is not required to conduct continuous monitoring. Semi-annual or annual (depending on status) wet chemistry stack tests can be considered instead.[68]

- Wisconsin: Hourly mass emissions using continuous emission monitoring is requested. They intended to apply the monitoring requirements from the CAMR before it was vacated. For the compliance alternative (mercury capture), the baseline mercury emission should be determined every 5 years and applied for the subsequent 5-year period. It is based on coal mercury content data obtained during a complete calendar year which is 2 years prior to the first year of the applicable 5-year period (i.e. 2010 mercury content data applied as baseline for 2012–2017 emissions).[69]

3.2.4 European Union

The *Air Quality Framework Directive* by the European Council defines the basic principles of a strategy for the quality assessment and management of criteria pollutants in ambient air.[70] The fourth Daughter directive of the framework published in 2004 relates to heavy metals including mercury.[71] However, in contrast to other criteria pollutants, no target ambient concentration for mercury is established by this legislation. Likewise, the European Council directive regarding large combustion plants (incl. coal-fired EGU) does not impose any specific mercury emission limits from stationary sources.[72] In spite of this, mercury emissions should be assessed and reported to the European Council by member states which are responsible for their emission standards by their industries in accordance with the recommendations from the 1998 Protocol on heavy metals to the UNECE Convention on long-range transboundary air pollution.[73]

The protocol requires the signatory member states not to exceed the mercury emission levels of a reference year (1990 or any year between 1985 and 1995). To achieve this objective, the

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[67] Maryland Department of the Environment, The Maryland Healthy Air Act – Chapter 27: Emission limitations for power plants, 2006.
[68] Michigan Department of Environmental Quality, Part11: Continuous emission monitoring, 2009.
[69] Wisconsin Department of Natural Resources, Wisconsin Administrative Code – Chapter NR446: Control of mercury emissions, 2008.
[70] European Union, Council Directive 96/62/EC of 27 September 1996 on ambient air quality framework and management, September 1996.
[71] European Union, Directive 2004/107/EC of the European Parliament and of the Council of 15 December 2004 relating to arsenic, cadmium, mercury and polycyclic aromatic hydrocarbons in ambient air, December 2004.
[72] European Union, Directive 2001/80/EC of the European Parliament and of the Council of 23 October 2001 on the limitation of emissions of certain pollutants into the air from large combustion plants, October 2001.
[73] United Nations Economic Commission for Europe, The 1998 Aarhus Protocol on Heavy Metals, 1998.