- a subbituminous fired 360 MW plant equipped with a fabric filter baghouse and dry scrubber, using chemically treated carbon scrubber (93% mercury reduction;
- a subbituminous fired 565 MW unit equipped with a fabric filter using sorbent injection (95% to 98% mercury removal); and
- a 220 MW unit burning lignite, equipped with cs-ESP, using a chemically treated carbon sorbent (90% mercury capture).

GAO (2009) provides summary information on capital costs of mercury control equipment. The average cost for plants equipped with activated carbon injection system only was \$3.6 million, ranging from \$1.2 million to \$6.2 million (costs in 2009 USD). These costs were inclusive of consulting, engineering, and installation of a continuous emissions monitoring system (CEMS). The average costs for plants that installed a system comprised of activated carbon injection, a polishing fabric filter baghouse, and CEMS was \$15.8 million, ranging from \$12.7 million to \$24.5 million.

4.0 Technical Feasibility and Performance Assessment

4.1 Introduction

Mercury control for the coal-fired power industry is a rapidly expanding field, with over 50 discrete technology options commercially available or under development. There is considerable variation in the level of development. Activated carbon injection represents one end of the technology spectrum, having undergone extensive pilot and plant scale testing for all major coal types, with performance assessments through parametric and long term testing, detailed cost estimates at varies levels of mercury removal, plus some commercial installations. Other technologies have undergone some long term performance tests but limited cost assessment and/or have been tested with only one fuel type or plant configuration. Technologies such as the Pahlman™ process have had pilot scale testing only, and have not been applied to full plant conditions. Finally, some technologies are still at the concept or bench-scale level of development.

As the objective of this study is to estimate the cost of mercury control to the fleet of coal-fired power plants in Canada, the report focuses on technologies that are commercially available as of 2010 (?) and for which cost information is available. As well, the study focuses on those technologies that have demonstrated mercury capture effectiveness of at least 70% for one or more of the major coal types.

4.2 Pre-screening

A three step process was used to screen technologies for consideration: pre-screening, analysis using a multi-criteria decision model, and cost comparison.

Technologies were screened out that were not mercury-specific, were at an early stage of development, or that resulted in mercury capture levels less than the minimum threshold requirement (70%). Non mercury specific technologies such as conversion to natural gas or biomass or installation of SO_2 scrubbers were screened out because they would not likely be adopted in response to a policy objective focusing on mercury control. However, such technologies may be adopted in response to other policy objectives, such as reduction in carbon footprint or SO_2 control, and result in a co-benefit in reduction in mercury emissions.

Developmental technologies were screened out because of insufficient information with respect to performance and cost at commercial scale at this time. It is recognized, however, that mercury control for coal-fired plants is still a developing field overall and technologies now in early development may prove commercially viable over time.

Finally, technologies that were unable to attain the threshold level of mercury reduction (70%) were generally screened out. However, it was recognized that some mercury control measures – such as coal blending and coal cleaning – while unable to achieve 70% reduction themselves could be combined with other approaches to achieve the threshold level of control.

Approaches to mercury control assessed using the analytic hierarchical process (AHP) multi-criteria decision model are identified below in Table 4-1~~Table 4-1~~. The % mercury capture or avoidance indicated in Table 4-1 is not the highest level reported in the literature. Rather, these values represent average values, and account for unit differences in fuel types burned and mercury capture by existing air pollution control devices (APCD). Table 4-2 identifies technologies that were screened out, and provides the rationale why they were not brought forward into the AHP analysis.

Table 4-1. Technologies kept in.

	Technology	Reason technology kept in	% Mercury capture or avoidance
	Status Quo	>70% mercury capture may be achievable with some APCD and coal configurations (i.e. bituminous burning unit equipped with baghouse)	50%
Fuel Blending	Coal blending	Considered in maritime provinces as method for reducing mercury. Being done to reduce pollutants. Fate similar to ACI. More common blends are bituminous and subbituminous, and subbituminous and lignite.	30%
Coal cleaning	Coal cleaning	At present, commercially undertaken for bituminous coals only. Modest level of mercury removal, but could be combined with other technologies. Improved quality of the coal. If coal shipped to site reduces transportation costs for same result.	30%
Carbon sorbent based technologies and technology combinations	Activated carbon injection (ACI)	Well developed technology, commercially developed, and tested on all coal types, and installed in operating units in Canada and U.S. A least cost mercury control option.	80%
	Brominated ACI	Well developed technology, commercially developed, and tested on all coal types, and installed in operating units in Canada and U.S. Another least cost mercury control option where the amount of AC needed is reduced with the addition of a sorbent. Total cost should be less than AC for same result. 80+% capture seen.	80%
	TOXECON™ (ACI + polishing FF)	Commercially tested, and has achieved high rates of mercury removal in sub-bit coals. The fly ash is saved for sale to concrete companies because it isn't contaminated since the pFF is after the ESP.	90%
	TOXECON II™	Commercially tested, and has achieved high rates of mercury removal in sub-bit coals. Cost saving in not requiring the expensive addition of a FF. Capture rate somewhat less since residence time is less than Toxecon. Does have some patent	70%

	Technology	Reason technology kept in	% Mercury capture or avoidance
		rights issues. Best results on bituminous and subbituminous coals.	
	ACI + sorbent enhancement additive (SEA)	Has been pilot and commercially tested, and preliminary cost estimates are available. Technology has been demonstrated with bituminous and subbituminous coals. Not sure about lignite coals. Quite similar to BACI however vendor support may not be as good. Shows high capture rates.	85%
In situ carbon sorbent production	Partial coal gasification	While tested only at pilot scale for bituminous , technology offers reasonable levels of mercury removal at potential lower cost than ACI. There may be some balance of plant issues. To get higher capture rates the sorbent loading rates are extremely high (32 lb/mmacf).	70%
	Thief process	While tested only at pilot scale, technology offers reasonable levels of mercury removal (although does not meet 70% capture threshold) at potential lower cost than ACI. It is not a mature technology.	60%

Table 4-2. Technologies screened out.

Technology Type	Technology	Reason technology screened out
Fuel switching	Convert to fuel oil	Higher operating costs and more important emission control considerations (other pollutants) relative to natural gas. Highly unlikely it would ever be considered as an option for mercury control.
	Switch to natural gas	Technology is available and will achieve nearly 100% mercury reduction. It would require a major retrofit of the station at a considerable cost to reach the same capacity factor. Since this isn't a mercury control for coal as the fuel, it is screened out.
	Switch to biomass	Technology is available and is being considered for use by plants in Ontario. Insufficient testing to date to make it a contender. This is not a mercury control for coal as a fuel and is screened out. It may show up with the coal blending sometime in the future.
Standard air pollution control devices (APCD)	SO_2 scrubber	Only cost effective (for high grade and high sulphur coals) in the context of multi-pollutant control, where both mercury and SO_2 removal are required. Wouldn't be considered for mercury control only.
	Selective catalytic reduction (NO_x control)	Cost prohibitive as mercury control technology, and effective only in limited plant configurations (i.e. bituminous burning plant equipped with w-FGD).). May be reconsidered for very high capture >90%.
	Baghouse	Too expensive to replace ESP with baghouse or put a full scale baghouse to polish for mercury.
Carbon sorbent based technologies and technology combinations	Iodine impregnated PAC	Developmental stage, not pilot tested at large scale facility. Appears a long way from commercial maturity.
	Sulphur impregnated AC	While very high level of mercury removals, Pilot scale testing only at very low flows. Too early a stage of research.
	Passivated PAC	Limited information – cement friendly PAC
Fixed carbon	MerSREEN	Technology capable of high mercury removal, but limited cost

Technology Type	Technology	Reason technology screened out
sorbents		information available for long term operation. Only looked at bituminous coal and only a slipstream pilot test so far.
	MerCAP	Low mercury capture rates after 3 months in operation. Gold plates appear to deteriorate over time as they are affected by acidic conditions.
Non carbon sorbents	Amended Silicates	Concrete friendly sorbent but mercury removal is relatively low (40% with bituminous coal). Only looked at bituminous coals.
	Sodium tetrasulphide	While high removal effectiveness (>90%) on PRB sub-bit coals when baghouse operating temperature is 300 F, performance drops of as temperature increases. Also, limited cost data.
	Calcium based sorbents	Potential for high temperature sorbents but mercury removal is limited (<50%). Technology at pilot stage, with no identified cost data. Only looked at bituminous and subbituminous coals.
	Metal oxide	Developmental stage with limited plant testing or cost data.
	Aluminum silicates	Does not remove mercury.
	Sulphur halides	No information on technology identified
Multi-pollutant control technologies	Pahlman™ process	High potential levels of mercury removal (up to 94%) but limited pilot scale testing, and no commercial installations. Discusses use of a baghouse reactor chamber which is a significant cost although there is limited cost information.
	Airborne process	Developed mainly for SO_2 and NO_x. Mercury removal capability not quantified. Small scale testing (5 MW)
	Mobotec Furnace Sorbent Injection (FSI)	Commercially available, and when used with limestone injection achieves reported 90% mercury removal – need to check. Primary purpose is low cost SO_2 removal. It is very costly.
Combustion modification	Lehig University LOI process	Results in increase in native mercury removal in bituminous coals, but far below threshold. May be an add-on technology, but not stand-alone. No cost data identified.
Advanced coal cleaning	WRI thermal treatment	Developmental, only at pilot scale testing. Concentrating on subbituminous and lignite coals.
	K-fuel	Developmental and latest information has the program on hold.
	Selective agglomeration	Not developed past bench-scale. Mercury removal rates similar to conventional coal cleaning.
	Advanced froth flotation	Not developed past bench-scale. Mercury removal rates similar to conventional coal cleaning.
	Chemical coal treatment	Laboratory testing only. Limited cost data.
	Biological coal treatment	Laboratory testing only. Mercury removal potential un-quantified
	Magnetic separation	MagMill™ tested at advanced pilot scale. Hg removal efficiency and cost data available for high sulphur bituminous coals.
Other technologies	Electro-catalytic oxidation	It is a multi-pollutant control system that recently had a pilot test. High removals of all the pollutants. No cost data and no commercial installation.
	Low Temp Mercury Capture	Developmental. Mercury capture rates are only 50%.
	Membrane based wet ESP	Low mercury removal. Is a multi-pollutant control system with a wet ESP. Not effective if high elemental mercury in the flue gas.
	Promoted filter bag inserts	High level of mercury removal reported but tested only at bench and/or small pilot scale. No cost data identified.
	Lignite fuel enhancement system	Mercury removal is very low (0.5%). May be useful for other plant objectives (multi-pollutant control, plant efficiency)

Technology Type	Technology	Reason technology screened out
	EERC hydrothermal	No performance or cost data identified.
	LoTox	Multi-pollutant technology, not specifically tested for mercury removal. No cost data available
	Integrated flue gas treatment	Uses condensing heat exchanger. Developed for SO_2 scrubbing. Limited data available on mercury removal.
Next Generation Coal Combustion	Integrated gasification combined cycle (IGCC)	Native mercury removal up to 42% with high sulphur bituminous coals, but cost not justified for mercury control (except with new plant) With installed IGCC plant, Pavlish 2005 makes economic case for low cost Hg removal with fixed carbon bed
	Indirectly fired combined cycle (IFCC)	Not currently used in N. America. Limited data on mercury control.
	Fluidized bed combustion	Several plants built using technology. Mercury removal up to 99% in plants burning bituminous coals. This is not a retrofit option, but new plant only
Oxidation systems	Oxidation additives + wFGD	Tested at commercial scale facilities, with mercury removal rates above 70%. Based on having a wet FGD in place already at the facility. It there is no need for a scrubber, then this technology is unwarranted. Would not be used strictly for mercury control.
	Fixed oxidation catalysts + wFGD	Tested at commercial scale facilities, with mercury removal rates above 70% Problem is that is in combination with wet scrubber. You have to have a wet scrubber. Limited value otherwise.
"Fully dressed" systems	SCR + FGD + ACI + FF	A new coal-fired plant would likely have this technology. It wouldn't be put in place to control mercury at an existing facility. New plant cost.
	LNB + ACI + SDA + FF	A new coal-fired plant would likely have this technology. It wouldn't be put in place to control mercury at an existing facility. New plant cost.

4.2.1 Technology evaluations

4.3 Evaluation methodology and criteria

A multiple criteria decision model based on the analytic hierarchical process (AHP) was used to aid in the comparison and assessment of mercury control technologies. The AHP model provides a rationale framework for technology choice by decomposing a multiple criteria decision problems into a series of sub-problems, each which can be evaluated independently (Saaty 2008). The elements of the AHP model are the model structure, consisting of major and sub-criteria, weighting factors used when comparing criteria and sub-criteria elements, and attribute scoring system used to score each of the technology choices by sub-criteria elements. The final component of the AHP process is assigning attribute scores to each of the technology choices. This was done through the use of quantitative data, where available, and by applying professional judgement.

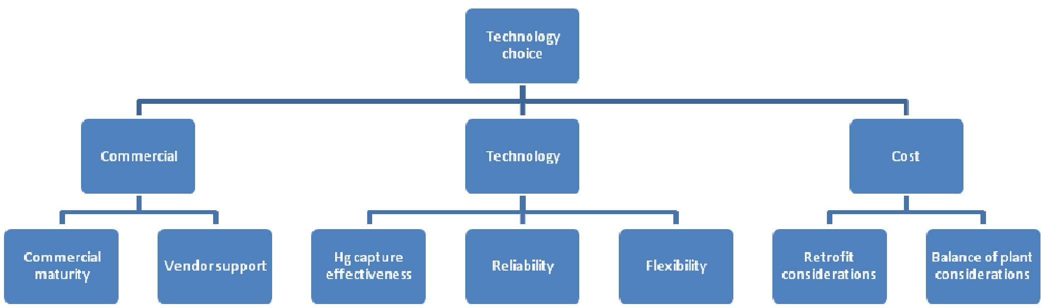
4.3.1 AHP model structure and criteria

Three major decision criteria and eight sub-criteria comprise the AHP structure. The major criteria are: commercial considerations, technology considerations, and cost considerations. Sub-criteria are as follows:

- **Commercial considerations:** commercial maturity, vendor support
- **Performance considerations:** mercury capture effectiveness, reliability, flexibility
- **Cost considerations:** retrofit, balance of plant, mercury fate/disposal

Figure 4-1 graphically illustrates the structure of the AHP model used in the mercury control technology evaluation.

Figure 4-1. Analytic hierarchical process model for mercury control technology evaluation.



4.3.2 Criteria scoring and weighting

4.3.2.1 Criteria preference scoring

In the AHP model, pairwise comparisons are made between sub-criteria within each major criteria, and between the major criteria. A ranking scale is used to rate preferences between any two criteria or sub-criteria. The model then converts the pair-wise comparisons into preferences for the elements included within each sub-criteria and within the major criteria. Table 4-3 provides the scale for pairwise comparisons used for ranking criteria preferences.

Table 4-3. Fundamental Scale for Pair-wise Comparisons (Criteria preferences).

Factor	***Explanation***
1	Both criteria are of equal importance
3	Experience and judgement slightly favour one criteria over the other
5	Experience and judgement favour one criteria over the other
7	Experience and judgement strongly favour one criteria over another
9	One criteria is absolutely favoured over another

4.3.2.2 Attribute preferences scoring

Attribute scoring uses the same fundamental scale of pair-wise comparison as with preference scoring. Pairwise comparisons are made on the basis of each technology's relative attributes with respect to each of the sub-criteria. Attribute scoring was based relative to a baseline technology, activated carbon injection (ACI). ACI was selected as the baseline technology because it is the most commercially mature mercury-specific control technology currently available. The attribute preference scoring scheme is presented in Table 4-4.

Table 4-4. Fundamental Scale for Pair-wise Comparisons (Criteria preferences).

Factor	Explanation
1/9	Technology is absolutely favoured over ACI for this criteria
1/7	Technology is strongly favoured over ACI for this criteria
1/5	Technology is favoured over ACI for this criteria
1/3	Technology is slightly favoured over ACI for this criteria
1	Technology is comparable to ACI for this criteria
3	ACI is slightly favoured over technology for this criteria
5	ACI is favoured over technology for this criteria
7	ACI is strongly favoured over technology for this criteria
9	ACI is absolutely favoured over technology for this criteria

Technologies are compared for each of the reference criteria. As the objective of the analysis is to assess the cost of mercury control to the Canadian coal-fired power industry, assuming implementation of technologies in 2010 only technologies that have been developed and tested to at least the pilot scale are included in the analysis.

Commercial considerations

1. **Commercial maturity**. Power stations are more likely to choose technology that has been commercially proven over technology still in a pilot testing or developmental stage. The reliability and costs associated with a technology are better understood if it has been employed in multiple plants over an extended period. Units burning bituminous and subbituminous coals are grouped together because of similarities in their configurations and technology characteristics.
2. **Level of technology support**. The extent by which a technology vendor provides technology support is an important consideration. Vendor support could include engineering, procurement, start up services, training, process optimization, and ongoing technology development. For technologies in which mercury removal effectiveness may be variable, depending on equipment set up and operating conditions, vendor support may be critical to its effectiveness. The highest level of vendor support is a performance guarantee, followed by vendor provided support during installation and operations. If the technology has no commercial vendor then the amount of support available may be limited or non-existent.

Performance considerations

1. **Mercury capture effectiveness.** The objective of the technology is to reduce mercury emissions. The ability of the technology to address regulatory requirements with respect to mercury emissions is an important criteria in technology choice. Based on maximum mercury removal potential relative to ACI. Average mercury removal effectiveness by ACI has been demonstrated at up to 90% for bituminous coals, 80% for subbituminous coals, and 70 % for lignite coals.

2. **Reliability.** The reliability of a technology includes both its consistency in mercury removal effectiveness and its operational reliability. As Unit down time is expensive at a coal-fired power plant the ability of a technology to maintain high operational reliability is critical. Long term (> 30 day) full plant tests of ACI systems show that mercury removal effectiveness remains stable over an extended period (Sjostrom 2008).
3. **Adaptability.** Adaptability refers to the ease by which a technology can be adjusted or re-configured in response to evolving operating conditions or regulatory requirements. A technology that can be combined with other technologies to achieve higher levels of mercury removal may be more attractive. For instance, ACI performance can be enhanced by, for instance, the addition of sorbent enhancements at the front end, or by installing a pulse-jet fabric filter at the back end (i.e. the TOXECON^{TM} process).

Cost considerations

Section 5.0 presents detailed capital and operating costs estimates for technologies short-listed through the technology evaluation. As part of the technology screening, three cost components are considered: retrofit/rebuild considerations, balance of plant, and mercury fate/disposal.

1. **Retrofit/rebuild considerations.** Retrofit refers to modifications required within an existing operating configuration while rebuild refers to rebuilding the operating configuration from scra^{tc}h. Technologies that require plant rebuilding can be cost prohibitive if it involves writing off a large amount of operating hardware. High retrofit costs may be involved if a technology requires extensive modification to current operating systems or plant configuration, or is limited by available space.
2. **Balance of plant considerations**. In a power plant, “balance of plant” refers to systems not primarily involved in the generation of electricity. These include coal preparation, pollution control, piping and ducting, plant utilities, and ash handling and disposal. The installation of a new technology may affect other plant systems resulting in increased capital or operating costs. For example, plants that control mercury levels in fly ash through the use of ACI may be unable to sell the fly ash due to its high level of carbon content. Technologies such as TOXECON^{TM,} fixed sorbent structures, and non-carbon based sorbents have been developed to address this B.O.P limitation of ACI.
3. **Mercury fate/disposal**. Mercury control technologies in Canada and U.S. focus on reducing stack emissions, as this is the principle regulatory driver in both Canada and the U.S. Mercury captured in the plant could potentially be released into the environment through a secondary vector, depending on the physical matrix containing the mercury, after it has been removed from the flue gas, and the effectiveness of the waste disposal technologies and procedures to permanently contain the captured mercury. While the respective effectiveness of waste disposal methods is outside the scope of this analysis, the potential for re-emission based on the properties of mercury containing plant waste products is considered.

4.3.3 Specified levels of mercury capture

As an objective of the technology evaluation is to compare technologies that capture a specified level of mercury (>70%, >80%, or >95% of mercury in as combusted coal) a binary factor was added to the AHP model to prevent technologies that have low capture effectiveness but score strongly in other respects from being selected. In addition, preference and attribute scores were adjusted where when making technology comparisons for the three specified levels of mercury capture for each of the Reference Scenarios.

4.4 Technologies recommended for cost analysis

From the numerous options available that promise mercury reduction from coal-fired electricity generating facilities, preliminary assessment was completed using the AHP model to determine the technologies that offer proven choices for power plant managers to meet mercury reduction requirements.

Mercury in coal will exist essentially in the elemental form at the boiler exit, regardless of its form in the feed coal. Depending upon operating conditions, the composition of the flue gas, and other factors, the mercury speciation will depart from an essential elemental mercury make-up, to include small amounts in particulate form, and a share of total mercury in oxidized form, where halogens and other oxidizers dominate the reducing chemicals present, like sulphur. Although the scenario are differentiated by coal rank, within the boiler flue gas, the key attribute input for design of mercury emissions control is the ratio of oxidized and elemental mercury species. Hence, some options for control of mercury emissions are designed to take advantage of the high activity of oxidized mercury, reflected in enhanced adsorption on active surfaces or elevated solubility in water, compared to the activity of elemental mercury. The remainder of the control technologies are based on modifying the operating system to increase the share of oxidized mercury species, or enhance the effectiveness of the control, itself.

Within the three coal ranks under discussion, there is also respective within-coal variability that produces a range of oxidized to elemental ratios during typical operation, so the scenarios possess highly-variable situations for a specific coal rank, but narrowing as the rank progresses from bituminous, through subbituminous to lignite. Thus, the effectiveness and range of opportunity for mercury reduction is also greatest for bituminous coals compared to lignites.

The suite of technology options is essentially the same for the three scenarios. The differences occur in the range of effectiveness, starting with the greatest at bituminous and diminishing through subbituminous to lignite. Table 4-5 lists the technology options that have passed the screening and preliminary assessment and will remain for consideration within the cost modelling and detailed assessment.

Table 4-5. Technologies for Cost Analysis – Mercury Emission Reduction from Coal-fired Utilities.

Technology or approach	**Rationale**
Status Quo	Appropriate where existing APCD configuration can achieve high mercury removal (i.e. bituminous-fired plant equipped with a fabric filter baghouse)
Coal blending	Coal blending has been demonstrated effective at reducing mercury by increasing halogen content of as-burned coal.
Coal washing	Units burning eastern bituminous coals benefit from reduced mercury content of as-delivered coal.
Activated carbon injection (AC)	Most commercially mature mercury control technology. Untreated carbon sorbents have achieved mercury reduction of over 70% in bituminous and subbituminous fired plants, equipped with cs-ESP
Brominated ACI	Chemically enhanced carbon sorbents have achieved higher levels of mercury removal than untreated sorbents. They also reduce system operating costs by lowering the required rate of sorbent loading.
ACI + oxidation additive or sorbent enhancement additive	Commercially tested, particularly on units firing low grade coals. Potential advantage over BACI is longer residence time and greater level of mercury oxidation.
ACI + polishing fabric filter baghouse	Commercially available technology has achieved high levels of mercury capture while preserving fly ash quality.
ACI + pFF baghouse plus sorbent enhancement additive	Some commercial testing. This configuration results in high level of oxidation and sorbent removal. Appropriate for low grade coals.
TOXECON™ II	Some commercial testing (subbituminous fired units only). Moderate level of mercury removal (70% plus) while preserving most fly ash for sale, at a fraction of the capital cost of pFF.

In addition to the technologies identified in Table 4-5, several technology combinations will be assessed further in Task 2. One of the Task 2 scenarios calls for an industry cost analysis assuming that the industry has been retrofitted to include NO_x and SO_2 control. NOx and SO2 control devices are expensive to install and operate, and are cost prohibitive as stand alone mercury control devices. However, if such equipment has already been installed, their co-benefit native mercury capture may reduced the cost of achieving mercury reduction targets through the use of dedicated mercury control equipment.

The proposed configurations assuming NO_x and SO_2 control considered in Task 2 will be based on the existing APCD configurations of Canadian units. These will include: oxidation additive plus wet scrubber, selective catalytic reduction plus wet scrubber plus ACI plus polishing fabric filter (pFF), and low NO_x boiler plus spray dry absorption plus ACI plus pFF.

4.4.1 Scenario 1 215 MW, 70% capacity factor, bituminous coal

Canadian utilities have made mercury-specific investments in air pollution control equipment to meet the Canada-wide Standards for 2010 for mercury from coal-fired electricity generating stations. This state of technology is a reference case for analysis and discussion within this Report and becomes the Status Quo in further analysis. Because of the range of sulphur-to-halogens ratios within bituminous coals, a wide variety of technologies are useful, but not all options listed in Table 4-8 will have the same effectiveness for all bituminous coal firings.

The options for mercury reduction can be conveniently grouped into three approaches. The first changes the mercury content in the fired fuel by cleaning, typically coal washing, or blending coals to obtain lower mercury content, or to provide an oxidants composition that will produce a high share of oxidized mercury from its combustion under typical conditions. The first can also be thought of as a form of pollution prevention, respecting coal combustion, because it avoids the entry of mercury to the system.

The second group of technologies are based on activated carbon sorbents. If oxidized mercury is present, it can be captured on Powdered Activated Carbon (PAC). If PAC is used, it can be made more effective by use of Sorbent Enhancement Additives, until all of the oxidized mercury is captured. If the mercury is captured on carbon, the collection of the mercury-containing carbon can be made more effective by changing the particulate collection system from an Electrostatic Precipitator to a Fabric Filter (FF). Fine particulate matter (PM), with its associated mercury that would have passed the ESP will be captured in a FF, increasing the effectiveness of mercury reduction.

If the mercury is not present as oxidized mercury, oxidants can be added to make it amenable to capture. The oxidants can be added to the PAC, like brominated activated carbon, so that some elemental mercury is oxidized in situ and adsorbed on the PAC. Oxidants, like hydrogen bromide, can be added with the coal at the front end of the process, producing an oxidizing environment in the boiler, so that oxidized mercury is dominant when the flue gases reach the sorbents at the back end.

It was noted above a FF will provide a better collection of PM fines, with adsorbed mercury, than ESPs. Hence the availability, or switch to, an FF provides better mercury capture, where the mercury is adsorbed on particles or PAC. The effective capture of mercury in the flyash may change the potential or price for ash sales, because of the presence of mercury and/or carbon. To retain the greatest sales potential, and to avoid the cost of full replacement of an ESP, a "polishing" FF (pFF) may be added to the ESP, to capture mercury at a location following the main collection of ash. This limits the mass of ash that might not be eligible for sale, or might need special management. The addition of a pFF also enhances the overall mercury collection, when added after an ESP, because it will remove fines that by-pass the ESP, but contain high mercury content.

If a pFF is not an optimum choice, the PAC can be added to the final field of an ESP, after the main collection of ash has occurred, again limiting the mass of ash in which mercury and carbon would be present.

The third technology group represents “opportunity” for mercury capture as a “co-benefit” of the presence of air pollution collection devices installed for other operational or environmental performance requirements. The use of Selective Catalytic Reduction for control of nitrogen oxides (NO_x) also has been shown to oxidize mercury in the flue gas. The activity of oxidized mercury is also reflected as enhanced water solubility, so the presence of a wet scrubber for sulphur oxides and acid gas control, provides a capture point for oxidized mercury.

If not all of the oxidized mercury is collected in the water of the scrubber, PAC can be added to provide to ability to capture the remainder, and the presence of a FF maximizes the mercury and sorbent collection. The presence of SCR and wet FGD occurs in response to simultaneous sulphur and nitrogen oxides requirements. Hence, the “opportunity” for mercury co-beneficiation, which can, as described, be further enhanced.

If the nitrogen oxide removal occurs using low- NO_x burners, there will often be increased carbon in the flyash. This can, under the right conditions, provide a useful surface for mercury capture, but it would not compete with PAC in terms of surface area/mass. Hence, SEA can be used in this technology chain to improve the potential capture of the carbon in ash. When PAC is used, a FF always provides better mercury capture efficiency than an ESP.

The actions to reduce the mercury entering the boiler, to enhance the likelihood of producing oxidized mercury, to provide the means to capture and remove oxidized mercury, or to take advantage of those present for other purposes, provide a number of options in their permutations and combinations. Some of the combinations have been developed to the point of trademarked technology, e.g. EPRI’s TOXECON is simply the addition of PAC to a standard system, with the addition of a pFF to enhance mercury removal. TOXECON II™ is the process of adding PAC to the final field of an ESP, as discussed. The choices among the technology options become an optimization of the benefits and costs of changing the amount of oxidized mercury present and the most effective removal from that state.

4.4.2 Scenario 2 400 MW, 70% capacity factor, subbituminous coal

The discussion within Section 4.3.2 relates to bituminous coal, where the greatest range of attributes exists compared to other coal ranks. Hence, almost all options are useful to some set of the bituminous coals or their blends. The same suite of options was determined to be useful for mercury emissions management from combustion of subbituminous coal, but there is a general loss of overall effectiveness, and the subbituminous coals do not provide the species ratios, or opportunity to reach those, which produce capture efficiencies as great as the potential for bituminous coals, without greater investment or greater plant modifications.

The preliminary screening provided the same suite of options as for bituminous, but individual facilities will posses attributes that will favour a narrower range than a typical bituminous plant. In Canada, another limiting factor to choice for plants burning subbituminous coals is that the coal mines are integral to the provincial economies, or owned, in full or in part, by the electricity generator. This means that some aspects, like coal blending, would not be chosen in those cases.

4.4.3 Scenario 3 170 MW, 70% capacity factor, lignite coal

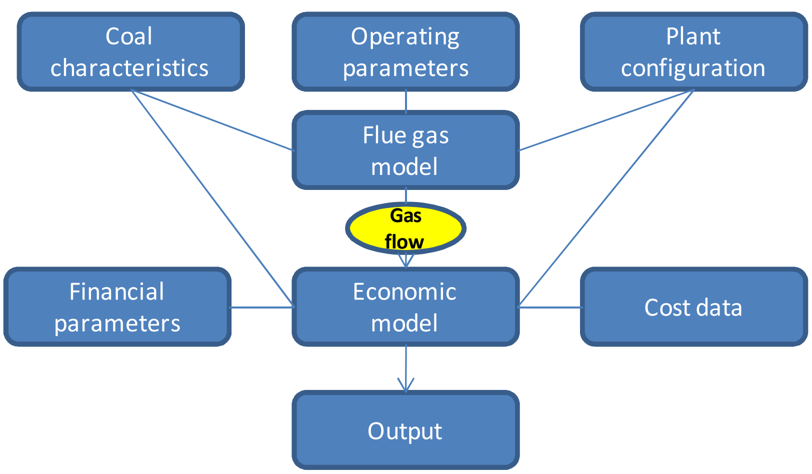
The comments from Section 4.4.2 are relevant to plants burning lignite in Canada. The presence of a major coal field provides less variability that available to plants burning imported coals or availing of other markets. Thus, the effectiveness of many of the technologies in Table 4-5 is reduced for the plants burning indigenous lignite coals. Further, lignite boilers have design differences from the units burning higher rank coals, some of which make the addition of enhancers and oxidizers either a greater impact on balance of plant, or less effective from a mass transfer perspective. In any case, the investigation of lignite facilities will require more attention to the technical details to provide the information on which decisions can be based.

5.0 Cost of Reducing Mercury

5.1 Methodology

The objective of the cost analysis is to estimate the costs of mercury control for three Reference Scenarios at three levels of mercury control: >70%, >80%, and over 95%. The cost assessment methodology is illustrated in Figure 5-1 and described below. First, simplifying assumptions, including coal characteristics and air pollution control configurations, were used to further define the Reference Scenarios used in the analysis. Second, a flue gas model was constructed to estimate standard and actual flow rate for each scenario. Third a spreadsheet cost model was constructed for each technology option. Fourth, a literature review was conducted to identify the capital and operating costs associated with mercury control for different technology options, coal characteristics, and air pollution control configurations. Fifth, cost data were adjusted to fit the Reference Scenarios. This included consideration of scale, coal characteristics, air pollution control, inflation, and currency exchange. Finally, the cost of reducing mercury at the different levels of mercury control was assessed on a first year and levelized basis. The results of this analysis were used, along with the technology assessment, to recommended technologies to be considered in the assessment of the cost to control mercury by the Canadian fleet of coal-fired power units.

Figure 5-1. Economic analysis outline



5.1.1 Reference Scenarios

As the cost assessment was based on only three Reference Scenarios, while there are 52 operating coal-fired power units in Canada a number of assumptions were made to ensure the cost analysis was conducted in a manner that best represented plant characteristics and operating conditions of the industry overall. This involved further defining the Reference Scenarios used in the analysis.

5.1.1.1 Scenario 1 – 215 MW plant burning bituminous coal, operating at 70% capacity

It was assumed Scenario 1 represented a generic facility operating in Nova Scotia. The eight units in Nova Scotia all burn bituminous coal or bituminous/coke blends. Petroleum coke will be essentially restricted to the single CFB unit as part of meeting reduction programs for SO_2 and mercury. As well, the capacity range of the Nova Scotia units at 150 – 183 MW, with typical size about 150 MW, is comparable with the generic unit size specified in the Scenario. Coal characteristics for Scenario 1 are based on the average properties of coals used at the four stations, based on data presented to the Canadian Electricity Association, Mercury Program, the last -years for which data on coal consumed by Nova Scotia electricity generators was publicly available (Table 5-1~~Table 5-1~~). The APCD configuration selected for Scenario 1 was no SO_2 control and cold-side electrostatic precipitator for particulate matter control, as this configuration is found in five of the eight Nova Scotian units. It was recognized that mercury control, based on activated carbon injection technology, has already been implemented at three of the four Nova Scotia Power Stations: Lingan, Point Tupper, and Trenton. However, to calculate the cost of mercury control to the entire Canadian coal-fired power industry, it was assumed these controls were not yet in place.

Other plants in Canada also burn bituminous coal, notably the H.R. Milner Station in Grande Cache, Alberta, Ontario Power's Lampton station, which burns mainly bituminous coals, sourced from either western Canada or eastern U.S, and OPG's Nanticoke station, which burns both bituminous and subbituminous coals. The H.R. Milner Station, which uses a filter fabric, enjoys a high level of native mercury capture (>85%), atypical of the industry overall. At 505 MW and 564 MW respectively, the Lambton and Nanticoke units are much larger than those specified in the Reference Scenario.

Table 5-1. Plant and coal characteristics by Reference Scenario.

	Scenario 1	Scenario 2	Scenario 3
Size	215 MW	400 MW	180 MW
Utilization	70%	70%	70%
APCD	cs-ESP, OFA	cs-ESP	cs-ESP, OFA
Coal grade	Bituminous	Subbituminous	Lignite
HHV (MJ/kg)	31.3	21.3	16.0
% Moisture	9.9	16.5	33.8
% Ash	6.1	21.5	19.2
% S	2.6	0.37	0.81
Cl (PPM) – dry basis	203	35.8	15.5
Hg (PPM) – dry basis	0.056	0.047	0.124
Gas flow (MMacfm)	688,860	1,262,480	589,680
Gas flow (MM acmm)	19,560	35,782	16,705
*Millions of actual cubic feet per minute			

** Millions of actual cubic metres per minute

5.1.1.2 Scenario 2 – 400 MW plant burning subbituminous coal, operating at 70% capacity

It was assumed that Scenario 2 represented a generic facility operating in Alberta. Of the 18 coal-fired units now operating in Alberta, 16 burn subbituminous coals. The 360 MW average size of those units (median size is 403 MW) is comparable with the generic unit size specified in Scenario 2. Coal characteristics for Scenario 2 are based on the average properties of coals used at the 16 units, based on data presented to the Canadian Electricity Association, Mercury Program, the last year for which data on coal consumed by Alberta utilities was publicly available (Table 5-1). The APCD configuration selected for Scenario 2 was no NO_x control, no SO_2 control and cold-side electrostatic precipitator for particulate matter control, as this configuration is found in 15 of the 16 Albertan units. It was recognized mercury control, based on activated carbon injection technology, is in the process of being implemented at all Alberta units, except H.R. Milner. However, to calculate the cost of mercury control to the entire Canadian coal-fired power industry, it was assumed these controls were not yet in place.

Other plants in Canada also burn subbituminous coal, including New Brunswick Power's Belledune station, Manitoba Hydro's Brandon Generating Station, and Ontario Hydro's Nantikoke Station (also burns bituminous) and Thunder Bay Station (burns mostly lignite, with about 25% PRB subbituminous coal).

5.1.1.3 Scenario 3 – 180 MW plant burning lignite coal, operating at 70% capacity

It was assumed that Scenario 3 represented a generic facility operating in Saskatchewan. SaskPower's nine units all burn lignite coal. While at 200 MW the average size of SaskPower's units is comparable to the generic facility size specified in Reference Scenario 3, unit sizes range from 66 MW (units 1 and 2 of Boundary Dam) to 310 MW (unit 1 of poplar River). For technologies such as activated carbon injection, plant scale affects the proportion of annualized capital cost included in the total annual cost. Adjustments for scale were made in the estimate of mercury control technology at the unit level in Task 2 (Section 6).

Coal characteristics for Scenario 3 are based on the average properties of coals used at the Saskatchewan units, based on data presented to the Canadian Electricity Association, Mercury Program, the last year for which data on coal consumed by SaskPower was publicly available (Table 5-1). The APCD configuration selected for Scenario 3 was no SO_2 control and cold-side electrostatic precipitator for particulate matter control, as this configuration is found in eight of the nine Saskatchewan units. It was recognized mercury control, based on activated carbon injection technology, has been implemented at the Emissions Control Research Facility (ECRF) at the Poplar River station. However, to calculate the cost of mercury control to the entire Canadian coal-fired power industry it was assumed these controls were not yet in place.

Ontario Power Generation's Aticokan and Thunder Bay stations also burn lignite coals. At 230 MW, Atikokan-1 is similar in size to the average unit in Saskatchwean. It also uses cs-ESP for particle control and has no SO_2, control. However, it uses a low NO_x burner, rather than over-fired air, for NO_x control. Thunder Bay units 1 and 2 are each 163 MW in size, have no SO_2 or NO_x control, and feature hot side ESP for particulate matter control.

5.1.2 Flue gas model

A spread-sheet sub-model was developed, using standard design assumptions, to estimate the flue gas flow rate from a coal-fired boiler, based on a large number of operating and fuel assumptions. The output of the sub-model model is an estimate of flue gas at actual stack conditions, on both wet and dry bases. The sub-model also provides the adjusted flue gas flow rate for a specified oxygen concentration in the flue gas. The sub-model provides inputs for unit capacity, coal ultimate analysis and higher heating value, pressure and temperature at stack exit, choice for the standard temperature and pressure, coal mercury content, excess oxygen in boiler, unburned carbon in fly ash, air in-leakage rate, assumed to occur principally in air preheater operation, boiler efficiency, stack diameter orvelocity, and annual capacity factor. The stoichiometric calculations account for water in combustion air and air leaking to the system, by using standard boiler design assumptions.

The sub-model operates with design or operational default values, where information is not available. The input of values for these variables is made in the worksheet where the changes in output variables can also be viewed in response to the new inputs. In this manner, the changes to estimates of flue gas flow can be viewed directly, as changes are made. This form of the input worksheet allows the set-up of a simulation structure to assess the sensitivity of the output costs to the operating choices available in the plant characteristics sub-model.

The sub-model plays a role at all stages of the project, starting with the ability to transform published data to the desired basis for the economic modelling. In Task 2, the flue gas model will be adjusted on a unit basis, for each of the units in the Canadian fleet. It will also be adjustable so, on a unit by unit basis, operating costs can be re-calculated if operators of a specific unit provide site-specific values for variable of interest. Finally, the sub-model provides a number of standard calculation approaches and assumptions to support the provision of cost information, when the desired input information in not available. Thus, assumptions starting with F-factors, followed by appropriate modifications for reference conditions, can replace the use of unit-specific coal ultimate analysis and operating conditions, to allow use of the full scope for the cost model.

The sub-model currently accommodates the configurations established for the Base Case Scenarios. Adjustments in flue gas flows to model wet flue gas desulphurization will be added for Task 2.

5.1.3 Information sources

The cost of mercury control technology for the three reference scenarios was estimated based on a literature review, and supplemented with information provided by technology vendors and power stations. The principal source of cost information was reports on full scale field tests of mercury control technologies conducted under the U.S. Department of Energy National Electricity Technology Laboratory (U.S. DOE/NETL) between 2002 and 2008 (see Table 3-2). Cost assessments in the topical reports were prepared using accepted techniques for preparing "study" level cost estimates (±30% accuracy). These include the U.S. Environmental Protection Agency's *Air Pollution Control Cost Manual* (APCCM) and the *Technical Assessment Guide* (TAG®) developed by the Electric Power Research Institute (EPRI). These estimates are based on mercury control system design criteria and operating parameters for specified total mercury removal targets, which were developed from parameter and long term tests conducted at each unit. They generally include a breakdown of capital costs (purchased equipment, direct and indirect installation costs) and operating costs (materials, labour, utilities, and replacement costs), as well as first year and levelized costs based on assumed capital recovery factors, discount rates, inflation, and equipment depreciation.

Another important source of cost information was the report titled *Mercury Control Technologies at Coal-Fired Power Plants Achieved Substantial Emissions Reductions*, prepared by the United States Government Accountability Office (U.S. GAO) in October 2009. The objectives of that report was to assess the effectiveness of existing mercury control technologies, the costs associated with mercury technologies currently in use, and the key issues faced by the U.S. EPA with respect to mercury control regulation. The U.S. GAO obtained information on the cost and effectiveness of mercury control technologies by conducting structured interviews with 13 coal-fired power plants that were operating mercury control technologies (all using activated carbon injection systems) and with six plants that were using existing air pollution controls to meet mercury emission reduction requirements (GAO 2009). The U.S. GAO also obtained data from EPRI and the DOE NETL program, and conducted a reliability review by collaborating data presented by plants with compliance reports submitted to state clean air agencies.

The GAO (2009) report summarizes average capital and operating costs incurred to achieve mercury reduction targets at 19 plants, including 14 plants equipped with sorbent injection systems and 5 plants equipped with sorbent injection systems plus a fabric filter baghouse (i.e. TOXECON configuration). However, the report does not disaggregate results by coal types used, installed air pollution control equipment installed, or level of mercury reduction attained. Therefore, the information contained in GAO (2009) was used to check cost estimates developed from other data sources.

Triton attempted to obtain cost information on mercury control directly from utilities that had installed or were in the process of installing mercury control equipment. Most plants declined to provide information on capital or operating costs associated with mercury control, either because such information was considered commercially sensitive or because they had signed confidentiality agreements with technology suppliers

5.1.4 Benchmarking

Information on costs for near-commercial or demonstration projects, and some early-use applications, is not necessarily reported on a common basis. The expression of mercury capture, or reduction, can be expressed on the basis of coal mercury as mined, as received, as fired, or dry. Reductions can sometimes be expressed across specific plant operations, like the SCR unit, the ESP, or the wet FGD unit. The use of sorbents is expressed as mass/time (e.g., pounds/h) or concentration in the gas stream (e.g., pounds/MMacf). When the mass/volume is used, the reference conditions for the volume can be actual conditions at the injection point, or standard conditions, where “standard”, itself, is not universal. The gas flow can be wet or dry under either set of conditions – actual and standard. The mass of the sorbent can be expressed as wet or dry. The addition of oxidant to the fuel can be expressed on any of the coal bases indicated above, and some reports express the oxidant as an “equivalent” gas concentration in the boiler (usually driven by limits for corrosion management of the boiler).

Typically, when mass or concentration of the sorbent is reported, the accompanying information is often limited to the nameplate capacity of the unit, and the coal rank (or ranks) burned. Consequently, using the cost data and determining its applicability for use with other power plants requires careful assessment of the bases under which the data were determined or obtained.

To this point in the work, Triton has assessed the published information to be able to properly apply it to the current cases of Task 1, and in preparation for its possible use with costing of mercury control options for the Canadian fleet. The first level of assessment was to assure the basis for costs by seeking coherence within the specific reports being used and by locating other reports from the same studies. Numerous calculations were completed to provide checks on the data or to assure coherence between multiple data sources that would be used for cost estimation in the Triton model. The second level of assessment was based on reproducing the summary conclusions reported in studies, by working from the inputs and assumptions published in the chosen studies. In many cases, the information was *not* made available to complete a robust assessment. For those cases, the only check was “coherency” of the results of a study with proven results from similar approaches.

Part of the validation was obtained from the Flue Gas sub-model, where a determination of the expected flow from the source plant was completed, and the mass or concentrations used to check the reported results from studies of interest. This activity will be ongoing as new information is discovered or provided. Given that, the data verification completed for this Report allows Triton to comfortably report costs, with confidence that the source data are internally coherent and further assessment will be completed to narrow the range of uncertainty. For this Report, the costs are expected to be biased high.

5.1.5 Cost assessment model

A cost assessment model was constructed for each technology option using Microsoft Excel. The model allowed capital, operating, and annualized costs by Reference Scenario for each of the three target levels of mercury control.

5.1.5.1 Plant configuration and coal characteristics

Plant configurations and coal characteristics used in the cost assessment model are outlined in Section 5.1.1. The generalized plant scenario of each Reference Scenario was considered in the choice of operating units from which comparable data was obtained. For example, data from units with fabric filters for particulate matter control were not considered in the analysis (other than those equipped with TOXECON configurations) since the native mercury capture by units equipped with fabric filters can differ substantially from those with electrostatic precipitators.

Flue gas flow for each scenario was calculated using a model that estimates flow as a function of Higher Heat Value (dry basis), boiler efficiency, air ingress from heaters/leaks, and excess air. Default values used in the cost estimate are based on a dry stoichiometric basis. The model allows user adjustment of oxygen concentration to more accurately estimated air flow based on actual operating conditions at different units.

5.1.6 Capital costs

Purchased equipment and direct installation costs were based on information reported in DOE/NETL topical reports, EPRI reports, and GAO (2009), adjusted into 2009 CDN$. For technologies based on sorbent injection a regression analysis was conducted to develop an equation that derives purchased equipment cost as a function of plant capacity. For other technologies, such as COHPAC, purchased equipment cost was based on average cost data, with more weighting given to recent estimates.

For this analysis, indirect installation and contingency costs were estimated at 35% of purchased equipment cost. This is consistent with technology cost estimates included in most topical reports prepared for US DOE/NETL Phase 1, II, and III mercury control technology evaluations. The 35% indirect installation and contingency cost is based on EPA APPCM methodology, in which indirect and contingency costs are estimated as follows (percentage of purchased equipment cost): general facilities (5%), engineering/home office (10%), process contingency (5%), project contingency (15%). The average consulting and engineering costs reported in GAO (2009) were similar to the EPA APPCM multipliers. For sorbent injection systems, average consulting and engineering cost was 10.6% of average total system cost, while for sorbent injection systems plus baghouse (i.e. TOXECON™) the average consulting and engineering cost was 9.1% of average total system cost.

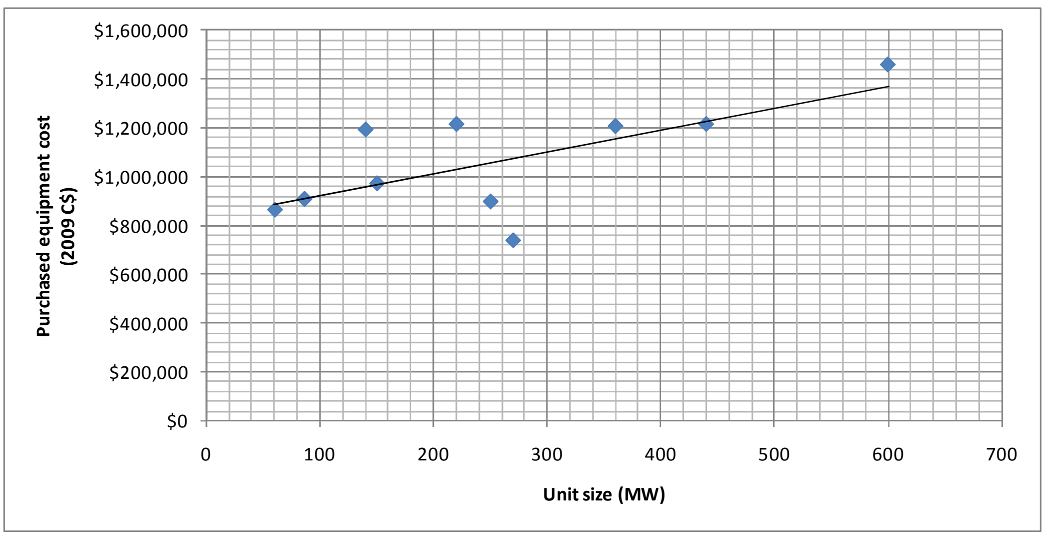
5.1.6.1 Activated carbon injection systems

Activated carbon injection (ACI) is the most widely evaluated and adopted system for mercury control in North America. ACI system components include a storage silo, sized to the unit capacity, and usually three injection trains (two operating and one spare). Installation includes concrete foundations for the silo, feeders, and blowers, electrical service, communication wiring, and general lighting. Additional costs include drainage and containment needed to collect and dispose wash down and other waste generated by the ACI system (Benson et. al. 2007).

Capital costs for adopting ACI were assessed for 15 as part of the DOE/NETL mercury program, while cost data on 19 boilers that feature ACI either retrofit or as part of new plant equipment are summarized in GAO (2009).

DOE/NETL reports indicate the purchased equipment and installation costs for ACI systems are only partly related to unit size. 2 shows the relationship between unit size and direct capital cost for ten coal-fired power units commercially tested for activated carbon injection tested in the DOE/NETL program.

Figure 5-2. Relationship between unit size and direct capital cost of activated carbon injection systems from US DOE/NETL topical studies.



When indirect cost and contingencies are factored in, the estimated capital cost for one ACI system in 2009 C$ averaged about $1.2 million, and ranged between $850,000 to $1.5 million (all figures in 2009 CDN$). This compares with an average capital cost of 2009 C$ 4.2 million for 14 coal-fired power stations reported in GAO 2009 (range $1.4 to $7 million). The GAO study included some very large units, which may have dual ACI systems. As well, the cost figures in the GAO report include mercury continuous emission monitoring systems (CEMS), which are not specified in the cost estimates contained in the DOE/NETL topical reports. However, after accounting for these differences the GAO figures suggest the capital cost of installing an ACI system may be 25% to 75% higher than reported in the DOE/NETL topical reports.

The GAO (2009) figures are based on data provided by operating facilities, and are more recent than the DOE/NETL data. Therefore, it was assumed that the GAO more accurately represent the current cost of installing sorbent injection systems. Accordingly, to estimate the cost of installing sorbent injection systems into units described in the Reference Scenario, the cost function derived between the linear relationships presented in Figure 5-1 was grossed up by 50%. Thus capital costs for sorbent injection systems were estimated using the following relationship:

Capital Cost (2009 CDN$) = $1,250,000 + $1,350 x Unit capacity in MW

5.1.6.2 Mer-Cure™

Capital cost data on the Mer-Cure™ system was not included in DOE/NETL reports on the technology. While the system is based around activated carbon injection, it incorporates a number of additional features, including a proprietary sorbent processing and delivery system. It is assumed that purchasers of Mer-Cure™ would pay a premium of 35% over standard ACI systems for the additional components and system performance of Mer-Cure™.

5.1.6.3 TOXECON™

The TOXECON™ configuration consists of sorbent injection downstream of the existing particulate control device and a new pulse jet fabric filter for collecting the spent sorbent. Typical components of a TOXECON™ system include (from Cummings and Derene 2006):

- PAC storage and injection systems for each unit connected to the PJFF
- Supply and return ductworks
- Diverter dampers to isolate each unit from combined flue gas ductwork
- PJFF baghouse
- Induced draft booster fans
- Compressed air system for PJFF cleaning
- Ash/spent carbon conveying and storage silo for PJFF hoppers, plus unloading system
- Electrical switchgear/motor control
- Control system
- Fan enclosure building
- Mercury CEMS (optional)

Hoffman and Ratafia-Brown (2003) estimated the capital cost for TOXECON™ at between $28 and $29 million for 500 MW bituminous or subbituminous burning plants, equipped with cold-side ESP (figures in 2003 US$). Two plants equipped TOXECON™ systems participated in the GAO (2009) survey. The average cost for the PJFF for these units in 2009 C$ was $23,000,000.

5.1.6.4 TOXECON II^{TM}

The TOXECON II^{TM} configuration contains similar equipment as a standard sorbent injection system. The difference is that with TOXECON II^{TM} the PAC injection lances are placed within the ESP box rather than within the ductwork. Limited data exists on the incremental capital costs associated with TOXECON II^{TM}. The direct capital cost of the TOXECON II^{TM} set up at the PRB-burning 880 MW Indpendence-1 unit was about $3.25 million (2007 US$) (Sjostrom May 2008), compared to $2.2 million for the ACI set up at the PRB/bituminous burning Monroe-4 unit (2006 US$) (Sjostrom Dec 2008). Both systems featured dual ACI configurations (i.e. 2 storage hoppers and 6 injection trains) of similar size. It is assumed, therefore, TOXECON II^{TM} costs an additional $550,000 (2009 CDN$) per set up over a standard sorbent injection system.

5.1.6.5 Sorbent enhancement of oxidant delivery skid

Sorbent enhancement additives and coal oxidants such as $CaCl_2$, $MgCl_2$, $CaBr_2$, and SEA2 can be delivered via an aqueous injection skid, which includes transfer pumps, flowmeters, controllers, and communications equipment. The installed cost of an aqueous injection skid is estimated at $790,000 (2009 C$) based on figures reported in Benson *et. al* (2007).

5.1.6.6 Continuous Emissions Monitoring System (CEMS)

A continuous emissions monitoring system (CEMS) can provide ongoing feedback on mercury levels in flue gas, enabling adjustment and optimization of mercury emissions control equipment. The installed capital cost of mercury CEMS is estimated at 2009 CDN$ 465,000, based on survey information collected by GAO (2009).

5.1.7 Operating costs

The principal operating costs for mercury control systems that use injected compounds to provide some oxidation of elemental mercury and absorb oxidized mercury is the sorbent cost, which depends on the amount of sorbent, usually expressed as a mass rate (e.g., pounds sorbent/h) or concentration (e.g., pounds sorbent/MMacf), required to achieve a desired level of mercury removal. The injection rates are sometimes referred to as “dosing rates” of sorbent. The sorbent injection required to achieve specific mercury removal rates for a number of coal types and APCD configurations is discussed further in Section 5.1.8.1.

Other costs considered included operating, maintenance, and supervising labour; utilities; replacement parts; spent sorbent disposal costs, plant overhead, taxes, and insurance. A number of identifiable mercury-specific labour costs are associated with some of the technology options. These are being identified as unexpectedly high labour needs related to operation of CEMs, if used. Ordering and scheduling for PAC delivery, transfer and storage can also add requirements for dedicated personnel. Initially, these will be dealt with in the cost model as operating overhead, while utilities are optimizing these, sometimes unplanned costs, which are often part of early use of new technologies. Table 5-~~Table 5-2~~ summarizes general operating cost factors, while Table 5-~~Table 5-3~~ provides operating cost assumptions by mercury control technology.

Table 5-2. General operating cost assumptions.

Sorbent & additives cost (2009 C$)		
Powdered activated carbon (PAC)*	$/kg	$1.29
Brominated PAC*	$/kg	$2.49
Mer-Clean™-8*	$/kg	$3.66
SEA1 (based on CaCl2)*	$/kg	$0.78
SEA2 (based on CaBr2)*	$/litre	$5.3
Labour, utilities, and disposal (2009 C$)		
Labour*	$/hour	$34.25
Benefits multiplier		1.3
Electricity	$/kwH	$0.05
Fuel (NG)	$/m^3	$0.65
Other operating costs		
Replacement parts	5% of purchased equipment cost unless otherwise specified	
Indirect overhead	20% of labour and replacement parts	
Taxes, insurance, administration	10% of direct operating and maintenance cost	
*Based on average hourly wage at large utilities (Statistics Canada 2009)		

Table 5-3. Operating cost assumptions by mercury control technology.

		ACI	BACI	BACI + pFF	TOXECON II	ACI + ADDITIVES	TOXECON + ADDITIVES	MER-CURE
O&M supervisory labour (20% of operating labour)	FTE*/yr	0.03	0.03	0.05	0.05	0.05	0.07	0.03
O&M operating labour	FTE/yr	0.15	0.15	0.25	0.25	0.25	0.35	0.15
O&M maintenance labour	FTE/yr	0.15	0.15	0.25	0.25	0.25	0.35	0.15
Electricity - fixed amount	kWh	195,000	195,000	195,000	195,000	195,000	195,000	195,000
Fuel (NG)	m^3/year					11,215	11,215	
Water	MT/year					8,712	8,712	
*Full time equivalent								

5.1.7.1 Sorbent cost and consumption rates

Sorbent consumption is the largest variable cost item related to mercury control in plants equipped with sorbent injection systems. Two of the key drives in the development and refinement of mercury control technology are to increase the total amount of mercury captured by sorbent injection and to reduce the consumption and therefore cost of sorbent (and additives) required to achieve a desired level of total mercury control.

Sorbent consumption rates by scenario were estimated by first identifying plants of comparable size and APCD configuration that have been subject to comparable mercury control technology, preparing consumption curves based on the plants identified, and then estimating the level of sorbent and/or additive required to achieve >70%, >80%, and >95% mercury capture.

Activated carbon injection (untreated powdered activated carbon)

Untreated activated carbon has only limited capability of removing mercury in lignite and subbituminous burning plants, and can achieved high levels of mercury removal in bituminous burning plants only with high sorbent loading levels (Table 5-4).

Table 5-4. Estimated total % mercury removal using un-enhanced PAC sorbents.

Coal grade	Comparable plants	Sorbents	Estimated % Mercury removal					
			60%	70%	80%	90%	95%	
Bituminous	Brayton Point*	DARCO®-Hg	N/A	11.0	17.0	20.0	N/A	Estimated Consumption (lbs/MMacf)
Subbituminous	Meremec-1*	DARCO®-Hg	1.0	5.0	N/A	N/A	N/A	
Lignite	Leland Olds-1*	DARCO®-Hg	5.0	10.0	N/A	N/A	N/A	
*Reference units equipped with cs-ESP for PM control Sources: Durhan et. al (undated), Sjostrom (Dec 2008), Wocken *et. al* (2009), Jones et. al (2006)								

Enhanced PAC and PAC plus additives

Phase II of the DOE/NETL mercury program focussed on increasing the effectiveness and reducing the cost of mercury capture. This included testing of enhanced activated carbon sorbents (Table 5-5), as well as carbon sorbents plus coal additives and/or sorbent enhancement additives (Table 5-6). Enhanced PAC's tested included Norit's DARCO® Hg-LH and Albemarle's B-PAC® brands.

No comparable lignite burning site tested for enhanced PAC was identified. Enhanced PAC injection rate for lignite units (up to 70% total mercury removal) estimated at 60% of injection rate of un-enhanced PAC.

Table 5-5. Estimated total % mercury removal using brominated PAC sorbents.

Coal grade	Comparable plants	Sorbents	Estimated % Mercury removal					
			60 %	70%	80%	90%	95%	
Bituminous	Lee-1*	B-PAC®	3.0	5.3	7.6	N/A	N/A	Estimated Consumption (lbs/MMacfm)
Subbituminous	Laramie-7* Meremec-1* Stanton-1*	DARCO®-Hg-LH, B-PAC®	0.8	1.5	2.5	4.0	7.0	
Lignite	Estimated**		3.0	6.0	N/A	N/A	N/A	
*Reference units equipped with cs-ESP for PM control								

** Estimate based on 50% of addition rate of un-enhanced PAC
Sources: Durhan et. al (undated), Sjostrom (Dec 2008), Wocken *et. al* (2009), Jones et. al (2006)

Alstrom's KNX® is a brominating additive that can be added to the coal prior to combustion or in the flue gas post combustion. When applied to units burning subbituminous coals the use of this additive reduces the injection rate required for un-enhanced PAC to a level comparable to using an enhanced PAC with no additive (Sjostrom Dec. 2008). Limited parametric and long-term data was available for different coal types and mercury removal rates. It was assumed that for subbituminous coals, the use of this additive would have a similar effect as using a brominated PAC (Table 5-~~Table 5-6~~).

Various sorbent enhancement additives have been tested to improve mercury removal from lignite burning units equipped with cs-ESP (Sjostrom December 2008). When added along with unenhanced sorbent, the level of sorbent required to achieve comparable levels of mercury removal is reduced and the total mercury removal capability of lignite burning units may be increased (6).

Table 5-6. Estimated total % mercury removal using PAC sorbents plus coal additives or sorbent enhancement additives.

Coal grade	Comparable plants	Sorbents	Estimated % Mercury removal					
			60%	70%	80%	90%	95%	
Bituminous								Estimated Consumption (lbs/MM acfm)
Subbituminous	Laramie-7* Labadie-2* Meremec-2*	DARCO®-Hg-+ KNX®-additive***	1.0**	1.5**	2.5**	4.5	N/A	
Lignite	Leland Olds-1*	DARCO®-Hg + SEA1****	1.8 (0.7)	4.4 (0.7)	8.5 (2.0)	N/A	N/A	

*Reference units equipped with cs-ESP for PM control

** Estimated

*** Additive rate = 1.6 gph (0.005 gallon/T)

**** Additive rate of SEA-1 in brackets

Sources: Sjostrom (Dec 2008), Wocken *et. al*. (2009), Jones et. al (2006)

Mer-Cure™

Alstom Power Inc's Mer-Cure™ process has been field-tested at several plants as part of the DOE/NETL field test program. The Mer-Cure™ process involves the use of a carbon-based sorbent along with a proprietary oxidation enhancing additive. The process involves injection methodology guided by computational fluid dynamics tools, designed to achieve optimal mercury vapour to sorbent mass transfer within the flue gas. A third feature of Mer-Cure™ is sorbent injection upstream of the air heaters. Claimed advantages of upstream injection include longer sorbent-mercury contact time, improved mercury oxidation kinetics, and potential to mitigate sulphuric acid related reduction in sorbent performance (Kang *et. al* 2008).

Mer-Cure^{TM} has been tested at Reliant Energy's 172 MW eastern bituminous burning Portland Unit-1, PacificCorp's 220 MW Dave Johnston Unit 1 and Lower Colorado River Authority's 480 MW Fayette Unit 3 (both burning PRB subbituminous coals), and Basin Electric's 220 MW Leland Olds Unit 1, firing North Dakota lignite. All of these units use cs-ESP for PM control. Fayette Unit 3 was the only unit equipped with a scrubber for SO_2 control Test results summarized in **Table 5-7** are based on the use of a trailer based demonstration system.

Table 5-7. Estimated total % mercury removal using Mer-Cure^{TM}

Coal grade	Comparable plants	Sorbents	Estimated % Mercury removal					
			60%	70%	80%	90%	95%	
Bituminous	Portland-1*	Mer-Clean^{TM}	2.8	4.5	6.4	8.0	9.0	Estimated Consumption (lbs/MMacf)
Subbituminous	Dave Johnston-1 * Fayette-3*	Mer-Clean^{TM}	0.25	0.4	0.5	0.8	1.1	
Lignite	Leland Olds*	Mer-Clean^{TM}	0.6	0.8	1.0	1.6	2.5	

* Reference facility equipped with cs-ESP for PM control

Sources: Kang et. al. (2008)

ACI + polishing fabric filter (TOXECON^{TM})

The TOXECON^{TM} configuration has been tested at the 270 MW bituminous burning Gaston Unit 3 and the 270 ME PRB subbituminous burning Presque Island Unit X. No lignite burning facilities equipped with TOXECON^{TM} were identified in this analysis. However, mercury capture based on sorbent injection was tested at North Dakota lignite burning Great River Energy's Stanton Station Unit 10, which is equipped with a conventional fabric filter. These results were used as a proxy for sorbent consumption of a lignite facility equipped with TOXECON^{TM} (Table 5-2~~Table 5-8~~).

Table 5-2~~8~~. Estimated total % mercury removal using TOXECON^{TM}.

Coal grade	Comparable plants	Sorbents	Estimated % Mercury removal					
			60%	70%	80%	90%	95%	
Bituminous	Gaston-3**	Not identified	1.5	1.9	2.3	3.1	3.5	Estimated Consumption (lbs/MM acfm)
Subbituminous	Presque Island - 7,8,9**	DARCO®-Hg DARCO®-Hg-LH	0.8	1.2	1.8	2.5	2.5	
Lignite	Stanton-10***	DARCO® Hg-LH	0.6	0.8	0.9*	1.0	1.5	

* Estimated

**Reference units equipped with cs-ESP for PM control plus polishing fabric filter in TOXECON™ configuration

*** Referenced units equipped with conventional fabric filter baghouse

*** Additive rate = 1.6 gph (0.005 gallon/T)

Sources: Sjostrom (Dec 2008), Wocken *et. al* (2009), Jones *et. al* (2006), Derenne *et. al* (2009)

A note of caution that with the exception of Gaston-3 there has been limited long term testing of the TOXECON™ configuration. Estimates for subbituminous coals are based primarily on parametric testing results reported by Derenne *et. al* (2009) for the Presque Island plant. Similarly, the estimated sorbent consumption for lignite powered station is based primarily on parametric test results from the Stanton-10 unit.

TOXECON II™

The TOXECON II™ configuration has only been tested at the PRB burning 880 MW Independence-1 unit. Consumption figures for subbituminous coal reflect both parametric and long-term tests, with long term test results indicated for mercury removal at the 80% to 90% level (Table 5-3~~Table 5-9~~). The TOXECON II™ configuration achieved a maximum of 90% mercury removal at injection of around 6.0 lbs of DARCO Hg-LH. The potential performance of TOXECON II™ in bituminous and lignite burning units is not estimated in this analysis.

Table 5-3~~9~~. Estimated total % mercury removal using TOXECON II™.

Coal grade	Comparable plants	Sorbents	Estimated % Mercury removal					
			60%	70%	80%	90%	95%	
Bituminous	Estimated		N/A	N/A	N/A	N/A	N/A	Estimated Consumption (lbs/MMacf)
Subbituminous	Independence-1	DARCO®-Hg-LH	1.0	3.2	5.0	6.0	N/A	
Lignite	Not estimated		N/A	N/A	N/A	N/A	N/A	

* Estimated

** Reference facility equipped with cs-ESP for PM control plus TOXECON II for mercury control

Sources: Sjostrom (Aug 2008)

TOXECON™ + coal additives or sorbent enhancement additives

There were no identified tests of TOXECON™ configuration in conjunction with coal additives or sorbent enhancement additives. However, the brominating additive KNX™ was tested at the 360 MW Holcomb-1 unit, which burns PRB subbituminous coal and is equipped with a FF baghouse. While adding KNX™ to the coal had no effect on mercury capture, when added at the spray dry absorber inlet, it resulted in an increase in mercury capture from 54% to 86% at 1.1

lb/MMacf of DARCO® Hg sorbent (December 2008). While the use of coal additives or sorbent enhancement additives may reduce sorbent consumption in plants equipped with TOXECON™ there is limited test evidence supporting this hypothesis. Therefore, the potential mercury removal effectiveness and cost of TOXECON™ plus coal additives or sorbent enhancement additives was not estimated.

5.1.8 Balance of plant costs

Two types of costs can be encountered in early use of a new technology, when the application occurs on an existing plant. Power plants have typically not been built with anticipation of major change, since a common station change is addition of new units. During retrofit, unplanned or unexpected costs can occur. Space limitations may result in sub-optimal placement of mercury control components and increased installation or operating costs. For example, due to space limitations a silo containing activated carbon sorbent may have to be placed far away from the location of injection lances, resulting in additional cost in conveying the sorbent to the injection site. Frequently, available space has an existing use, so costs appear in other plant accounts to replace the lost use.

As well, power generators will often encounter expected and unexpected “balance of plant” costs. The “balance of a power plant” is the remaining systems, components and structures beyond the prime mover and energy recovery systems. Often, when a new technology or process is added to an existing plant, there will be impacts on the “balance of plant”, beyond the changes made in the core of the operation. Balance of plant costs are common within the tightly designed initial configurations represented by most well-operating power plants. A number of balance of plant issues affect the cost of installing and operating mercury control equipment.

One of the largest balance of plant costs relates to addition of carbon and consolidation of mercury in fly ash, which can prevent its use in recycle or re-use, like sale as cement replacement or other use. As a result, plants employing mercury control technologies based on activated carbon injection may both forgo ash sales revenue and incur additional cost in disposing ash they would have otherwise sold. In other cases, the mercury control may be shut down for a period to harvest flyash the meets aesthetic, technical or regulatory specifications. This may mean that greater reductions may be necessary to meet regulatory requirements. Incremental mercury reduction costs are usually greater than the design performance and may not be offset by ash sales.

Additional balance of plant issues have been identified for activated carbon based technologies (GAO 2009, other sources). These included corrosion or erosion of duct works, , and duct fires cost by elevated carbon levels in flue gas. GAO (2009) reports these balance of plant issues were addressed at low cost (<$10,000) through process engineering at the plants that were using ACI based systems.

5.1.9 Financial parameters and sensitivity analysis

The cost to control mercury was calculated using both the annualized and levelized cost methods, and presented by total annual cost, cost per MW of plant capacity, and cost per kg of mercury captured. Financial parameters used in the analysis are presented in Table 5-4~~Table 5-10~~.

Table 5-4~~10~~. Financial parameters and sensitivity analysis.

Economic assumptions	
Discount rate	10%
Interest on debt	10%
Interest on equity	10%
Interest on funds used during construction	10%*
Capital structure	70% debt:30% equity
U.S. Canada e/r	1.14
Inflation	2%
Cost escalation	3%
Depreciation rate	10% (declining basis method)
Equipment life	20 years
Capital recovery factor	0.117
Indirect capital costs + contingencies	35% of purchased equipment cost unless otherwise specified
*It is assumed interested on funds used during construction is capitalized	

5.2 Mercury control costs by Reference Scenarios for 70% capture

5.2.1 Status Quo

The Status Quo scenario applies to facilities that are achieving at least 70% total mercury removal with existing air pollution control devices (APCD) and coal procurement strategies. In theory, native mercury removal of over 70% can be achieved in plants equipped with a filter fabric baghouse, burning bituminous or subbituminous grades, or bituminous burning units equipped with cs-ESP plus wet FGD. While several Canadian plants (i.e. H.R. Milner) achieve 70% or more total mercury capture without specialized mercury removal equipment it is assumed that most Canadian units will not be able to achieve this target without using supplementary mercury control measures.

5.2.2 Coal blending or switching

Blending small quantities of higher chlorine bituminous coal into lower grade coals has been demonstrated to increase mercury capture in plants equipped with a fabric filter baghouse. Coal blending conducted at Halcomb Station showed that blending 15% Western Bituminous coal overall mercury capture at the 360 MW fabric filter equipped unit increased from 0% to 80% (Sjostrom December 2008). The Holcomb facility is equipped with a spray dry absorber, which was stripping HCl from the flue gas. The addition of small quantities of higher chlorine coal increased the chlorine level at the outlet of the SDA, allowing sufficient oxidation of elemental mercury, and subsequent removal by fabric filter.

With the exception of Ontario, most Canadian coal-fired power stations burn coal grades that are naturally present in the region the plant is situated. Thus, most Alberta plants access subbituminous coal deposits, which cover most of central Alberta, Saskatchewan plants access natural endowments of lignite, while Nova Scotia units burn local and imported bituminous blends.

Nova Scotia units (Scenario 1) can potentially improve mercury capture by coal blending, since a proportion of coal burned at these stations is imported, from the Eastern United States and South America. At present, Nova Scotia power stations use blending as a means of achieving sulphur emission objectives, but not for mercury control. Bituminous grades burned at Nova Scotia units are typically have low to moderate mercury levels (0.02 to 0.10 PPM), high chlorine levels (335 to 820 PPM) and high levels of sulphur (2.5% to 5 %). Coal blending could help optimize the oxidation/reduction qualities of combusted coal to maximize mercury capture by cs-ESP. However, native mercury removal would still be limited to 30% to 40% due to inherent limitations of cs-ESP for removal of oxidized mercury. The estimated additional annual cost for coal blending in Scenario 1 is $400,000 per year. This includes land for stock piling ($30,000/year) plus labour, equipment, and overhead for logistics, stockpile management, and blending ($370,000/year).

For Scenario 2 (Albertan unit burning subbituminous coal) and Scenario 3 (Saskatchewan unit burning lignite coal), coal blending is unlikely a cost effective method for mercury control. Units equipped with cs-ESP for mercury control have limited mercury removal capability even when burning bituminous grades because of the low ash residence time within the ESP. Thus blending small quantities of lower mercury level or higher halogen level coals would likely result in only a small improvement in mercury capture. Secondly, the additional cost involved in purchasing higher grade coal are considerable both due to the higher purchase price of the coal and transportation costs. Most Albertan coal-fired plants are located near Edmonton, about 400 km east of the bituminous coal mines. The Saskatchewan power stations are located in southern Saskatchewan, about 1000 km south east of Edmonton.

For Scenario 2 the estimated annual cost of blending with 15% western Albertan bituminous coal is $4.7 million to $6.7 million, depending on additional coal price. For Scenario 3, the estimated annual cost is $6.6 to $7.6 million (Table 5-5~~Table 5-2~~).

Table 5-5~~2~~. Estimated annual cost of coal blending.

	Scenario 1	*Scenario 2*	*Scenario 3*
Total coal consumption (MT)	506,000 MT	1.3 million MT	830,000 MT
15% blended coal (MT)		200,000 MT	125,000 MT
Total mercury removal*	30% to 40%	Unknown	Unknown
Additional coal cost**	–	$1.0 to $2.0 million	$600,000 to $1.2 million
Rail shipping***		$2.3 million	$5.0 million
Storage and blending****	$400,000	$400,000	$400,000
Total	$400,000	$3.7 to $4.7 million	$6 to $6.6 million

* Inclusive of native capture prior to blending
** Based on $5/MT to $10/MT premium for higher grade coal
*** Based on 400 km shipping distance (Scenario 2) and 1400 km shipping distance (Scenario 3). Rail shipping cost at $0.0287 per MT per km (Railway Association of Canada 2009)
**** Inclusive of labour, land, and equipment for additional logistics, storage management, and blending operation.

5.2.3 Coal cleaning

Eastern and mid-western bituminous coals are typically cleaned at the mine site to reduce sulphur and ash content, and increase heat content. For higher grade coals, destined to be transported to end-users the costs associated with coal cleaning are offset by the higher value of the delivered coal. As conventional coal cleaning techniques involve a form of gravimetric separation, they are effective at removing sulphur (and associated mercury) only when there is a substantial mineral component to the raw coal. Cleaning removes about 35% on average of mercury in bituminous coals.

Coal washing cost tends to be mine specific proprietary information and there is limited public literature on this topic. Bhagwat *et. al* (2009) estimate the cost of washing Illinois No. 6 bituminous coal at $1.58 per ton of clean coal (2008 USD). Subbituminous or lignite grade coals are not typically washed prior to use. Conventional cleaning based on gravimetric separation would likely only marginally reduce mercury levels in low grade coals because of low levels of pyritic minerals, and a higher proportion of mercury bound in volatile fractions. Most western Canadian utilities operate at the "Mine Mouth" thus washing is not required to improve transportation logistics.

As Eastern bituminous coals are generally washed prior to delivery it is assumed there is no incremental benefit to coal washing for Scenario 1. There is insufficient data to develop an economic case for coal washing for scenarios 2 and 3.

5.2.4 Scenario 1

Activated carbon injection, using a brominated sorbent was estimated the most cost effective strategy for a bituminous burning 220 MW unit, equipped with cs-ESP (Table 5-11). At 70% mercury capture loading rates for brominated PAC sorbent are about half that of unenhanced PAC (5.3 vs. about 10.0 lb/MMacf), resulting in equivalent annual sorbent cost, given the higher price of brominated sorbents. Using brominating coal additives in association with unenhanced PAC may result in the lowest overall sorbent cost for plants burning bituminous coals. However, given limited test data for this option, the estimated costs for Scenario 1 are based on using brominating PAC for mercury control.

The total capital cost installing an BACI system for Scenario 1 is estimated at \$2.1 million, and annual operating costs at \$1.9 million and First Year cost of \$2.2 million (Table 5-6~~Table 5-11~~). 20 year levelized cost, assuming a 10% discount rate is \$3.5 million.

Units that sell their fly ash would incur additional disposal cost and forgone revenue if they use BACI for mercury control. However, for Scenario 1, the estimated amount of revenue foregone and added disposal cost would not justify adding a polishing fabric filter, assuming target mercury capture of about 70% (Table 5-6~~Table 5-11~~). Toxecon II™ may be a cost effective means of maintaining fly ash sales at the 70% mercury capture level, though the effectiveness of Toxecon II™ in bituminous burning units has not been evaluated.

Table 5-6~~11~~. Scenario 1 (220 MW bituminous burning unit) Total, annual, and levelized cost for 70% mercury capture.

	ACI	BACI	BACI + pFF	TOXECON II	ACI + ADDITIVES	TOXECON + ADDITIVES	Mer-Cure
Capacity (MW)	215	215	215	215	215	215	215
Capacity factor	70%	70%	70%	70%	70%	70%	70%
% mercury recovery	70%	70%	70%	70%	70%	70%	70%
Coal type	Bituminous	Bituminous	Bituminous	Bituminous	Bituminous	Bituminous	Bituminous
PAC loading (lbs/MACF)	11.00	5.3	1.9	N/A	N/A	1.43	4.5
PAC cost (2009 C$/lb)	0.59	$1.12	$0.59	$1.12	$0.59	$1.12	$1.66
SEA loading (lbs/MACF)					0	0.005	
SEA cost (2009 C$/lb)					$2.41	$2.41	
Capital cost (total)	$2,105,639	$2,105,639	$24,455,384	not estimated	not estimated	$26,501,566	$2,671,680
Capital cost (annualized, based on 20 year equipment life)	$247,328	$247,328	$3,016,146	not estimated	not estimated	$3,112,864	$313,815
Operating costs							$0
Sorbents, oxidants, and sorbent enhancing chemicals	$1,613,044	$1,476,669	$278,617	not estimated	not estimated	$126,771	$1,867,392
Replacement parts	$77,013	$77,013	$103,967	not estimated	not estimated	$103,967	$103,967
Labour	$38,289	$38,289	$51,660	not estimated	not estimated	$65,031	$38,289
Utilities	$9,750	$9,750	$9,750	not estimated	not estimated	$9,750	$9,750
Overhead & taxes	$183,938	$167,830	$26,870	not estimated	not estimated	$44,533	$209,598
Spent sorbent disposal	$24,700	$11,901	$4,266	not estimated	not estimated	$3,200	$10,105
Balance of plant (no ash sales)							$0
Balance of plant (ash sales)	$449,971	$449,971	$0	not estimated	not estimated	$0	$449,971
Total operating costs (no ash sales)	$1,946,734	$1,781,452	$475,130	not estimated	not estimated	$353,251	$2,239,100
Total operating costs (ash sales)	$2,396,705	$2,231,422	$475,130	not estimated	not estimated	$353,251	$2,689,071
							$0
Total Year 1 costs (no ash sales)	$2,194,062	$2,028,779	$3,491,276	not estimated	not estimated	$3,466,115	$2,552,915
Total Year 1 costs (ash sales)	$2,644,032	$2,478,750	$3,491,276	not estimated	not estimated	$3,466,115	$3,002,886
First year depreciation cost (based on 10% depreciation rate)	$210,564	$210,564	$2,445,538	not estimated	not estimated	$2,650,157	$267,168
						$0	$0
Levelized annual cost (based on 20 year equipment life) no ash sale	$3,458,553	$3,214,805	$4,666,201	not estimated	not estimated	$5,067,995	$4,048,704
Levelized annual cost (ash sale)	$4,181,332	$3,937,584	$4,666,201	not estimated	not estimated	$5,067,995	$4,771,483

5.2.5 Scenario 2

The Mer-Cure™ system appears the most cost effective strategy for a subbituminous burning 400 MW unit, equipped with cs-ESP, assuming the unit does not sell its fly ash (Table 5-7~~Table 5-12~~). The very low sorbent loading rate (0.4 lbs/MMacf) needed to achieve 70% mercury removal using Mer-Cure™ resulted in much lower operating costs than conventional ACI systems using either unenhanced or brominated PAC sorbents. The annual cost of using an unenhanced PAC in combination with a brominating coal additive (SEA2) is comparable to using a brominated PAC. Assuming a delivered sorbent cost of $1.65/lb, the First Year cost for using Mer-Cure™ was estimated at $860,000 and the 20 year levelized cost is estimated at $1.3 million.

If the unit is selling fly ash, then the use of Mer-Cure™ could result in foregone ash sales and additional ash disposal cost. Assuming the unit foregoes ash sales based on 50% of the quantity of fly ash generated each year, ash sales price of $21/MT and ash disposal cost of $20/MT then the unit would incur and additional $4.1 million in costs and forgone revenue each year. In this case, the lowest cost technology may be TOXECON II.™, Due the high capital cost, the use of

ACI plus a polishing fabric filter is not economically competitive at the 70% mercury recovery level.

Table 5-7~~12~~. Scenario 2 (400 MW Subbituminous burning unit) Total, annual, and levelized cost for 70% mercury capture.

	ACI	BACI	BACI + pFF	TOXECON II	ACI + ADDITIVES	TOXECON + ADDITIVES	Mer-Cure
Capacity (MW)	400	400	400	400	400	400	400
Capacity factor	70%	70%	70%	70%	70%	70%	70%
% mercury recovery	70%	70%	70%	70%	70%	70%	70%
Coal type	Sub-bituminous	Sub-bituminous	Sub-bituminous	Sub-bituminous	Sub-bituminous	Sub-bituminous	Sub-bituminous
PAC loading (lbs/MACF)	10	1.5	1.2	3.2	1.5	0.9	0.4
PAC cost (2009 C$/lb)	$0.59	$1.12	$0.59	$1.12	$0.59	$1.12	$1.66
SEA loading (lbs/MACF)					0	0.005	
SEA cost (2009 C$/lb)					$2.41	$2.41	
Capital cost (total)	$2,367,876	$2,367,877	$24,792,546	$2,945,376	$4,020,046	$26,855,586	$3,025,702
Capital cost (annualized, based on 20 year equipment life)	$278,130	$278,130	$3,057,729	$345,963	$472,193	$3,154,447	$355,398
Operating costs							$0
Sorbents, oxidants, and sorbent enhancing chemicals	$2,478,417	$706,349	$808,355	$1,506,877	$499,005	$136,189	$280,546
Replacement parts	$89,500	$89,500	$120,825	$89,500	$141,801	$120,825	$120,825
Labour	$38,289	$38,289	$51,660	$51,660	$51,660	$65,031	$38,289
Utilities	$9,750	$9,750	$9,750	$9,750	$25,752	$9,750	$9,750
Overhead & taxes	$273,049	$92,047	$28,556	$176,111	$10,332	$47,161	$52,599
Spent sorbent disposal	$37,952	$5,693	$4,554	$11,922	$5,693	$3,416	$1,518
Balance of plant (no ash sales)		$0	$0	$0	$0	$0	$0
Balance of plant (ash sales)	$4,012,697	$4,130,718	$0	$0	$4,130,718	$0	$4,130,718
Total operating costs (no ash sales)	$2,926,956	$941,627	$1,023,700	$1,845,820	$734,242	$382,371	$503,527
Total operating costs (ash sales)	$6,939,653	$5,072,345	$1,023,700	$1,845,820	$4,864,959	$382,371	$4,634,244
							$0
Total Year 1 costs (no ash sales)	$3,205,086	$1,219,757	$4,081,429	$2,191,782	$1,206,435	$3,536,818	$858,925
Total Year 1 costs (ash sales)	$7,217,783	$5,350,475	$4,081,429	$2,191,782	$5,337,153	$3,536,818	$4,989,642
							$0
First year depreciation cost (based on 10% depreciation rate)	$236,788	$236,788	$2,479,255	$294,538	$402,005	$2,685,559	$302,570
							$0
Levelized annual cost (based on 20 year equipment life) no ash sale	$5,074,356	$1,920,214	$4,756,430	$3,440,522	$1,828,065	$5,174,403	$1,334,660
Levelized annual cost (ash sale)	$11,519,872	$8,555,303	$4,756,430	$3,440,522	$8,463,154	$5,174,403	$7,969,750

5.2.6 Scenario 3

The Mer-Cure^{TM} system, may be the lowest cost option for lignite burning plants due to a potential low sorbent loading rate needed to achieve 70% mercury capture (Table 5-13). Conventional PAC plus oxidation additives would come in a distant second place, as the rate of PAC injection required to achieve 70% reduction may be about 5 X higher than the amount needed using Mer-Cure^{TM}.

Table 5-8~~13~~. Scenario 3 (220 MW lignite burning unit) Total, annual, and levelized cost for 70% mercury capture.

	ACI	BACI	BACI + pFF	TOXECON II	ACI + ADDITIVES	TOXECON + ADDITIVES	Mer-Cure
Capacity (MW)	180	180	180	180	180	180	180
Capacity factor	70%	70%	70%	70%	70%	70%	70%
% mercury recovery	70%	70%	70%	70%	70%	70%	70%
Coal type	Lignite	Lignite	Lignite	Lignite	Lignite	Lignite	Lignite
PAC loading (lbs/MACF)	10.0	6.0	0.8	N/A	4.4	0.6	0.8
PAC cost (2009 C$/lb)	$0.59	$1.56	$1.12	$1.12	$0.59	$1.12	$1.66
SEA loading (lbs/MACF)					$0.70	$0.00	
SEA cost (2009 C$/lb)					$0.35	$2.41	
Capital cost (total)	$2,056,026	$2,056,027	$24,391,596	not estimated	$3,599,048	$26,434,589	$2,604,704
Capital cost (annualized, based on 20 year equipment life)	$241,500	$241,500	$3,008,279	not estimated	$422,743	$3,104,997	$305,948
Operating costs							$0
Sorbents, oxidants, and sorbent enhancing chemicals	$1,052,071	$1,670,936	$434,645	not estimated	$507,098	$82,062	$238,179
Replacement parts	$74,650	$74,650	$100,778	not estimated	$126,951	$100,778	$100,778
Labour	$38,289	$38,289	$51,660	not estimated	$51,660	$65,031	$38,289
Utilities	$9,750	$9,750	$9,750	not estimated	$25,752	$9,750	$9,750
Overhead & taxes	$126,745	$187,020	$28,556	not estimated	$10,332	$39,743	$46,357
Spent sorbent disposal	$16,110	$9,666	$1,289	not estimated	$7,089	$967	$1,289
Balance of plant (no ash sales)		$0	$0		$0	$0	$0
Balance of plant (ash sales)	$2,250,342	$2,316,529	$0	not estimated	$2,316,529	$0	$2,316,529
Total operating costs (no ash sales)	$1,317,615	$1,990,311	$626,677	not estimated	$728,881	$298,330	$434,642
Total operating costs (ash sales)	$3,567,957	$4,306,840	$626,677	not estimated	$3,045,410	$298,330	$2,751,171
							$0
Total Year 1 costs (no ash sales)	$1,559,115	$2,231,811	$3,634,956	not estimated	$1,151,624	$3,403,327	$740,590
Total Year 1 costs (ash sales)	$3,809,457	$4,548,340	$3,634,956	not estimated	$3,468,153	$3,403,327	$3,057,119
							$0
First year depreciation cost (based on 10% depreciation rate)	$205,603	$205,603	$2,439,160	not estimated	$359,905	$2,643,459	$260,470
							$0
Levelized annual cost (20 year) no ash sale	$2,440,200	$3,545,476	$4,644,435	not estimated	$1,751,522	$4,972,015	$1,153,053
Levelized annual cost (20 year) with ash sale	$6,054,880	$7,266,471	$4,644,435	not estimated	$5,472,517	$4,972,015	$4,874,047

5.3 Highest level of mercury capture

Activated carbon injection using brominated PAC has achieved mercury removal rates of 80% in long term tests at Lee-1 (Table 5-9~~Table 5-14~~). A total mercury removal rate of 90% was recorded at parametric testing at Brayton Point station, at sorbent loading of 20 lbs/MMacf. Two technologies have demonstrated total mercury removal over 95%, TOXECON™ and Mer-Cure™.

Table 5-~~9~~14. Maximum documented mercury removal for bituminous burning plants.

Technology	Sorbent	Unit	APCD	Sorbent Injection rate (lbs/Mmacf)	Test type	% Total Hg removal	Source
ACI	Brominated PAC (B-PAC™)	Lee-1	cs-ESP	8	Long term	80%	Jones et. al. (2007)
ACI	PAC (DARCO-Hg)	Brayton Point	cs-ESP	20	Parametric	90%	Durham et al
TOXECON™	PAC	Gaston-1	hs-ESP, polishing FF	3.5	Parametric	95%	Bustard (2004)
MER-CURE™	MER-CLEAN™ 8-21	Portland-1	cs-ESP	8.5	Long term*	96%	Jones et. al (2007)

Un-enhanced PAC has achieved total mercury removal over 90% in cs-ESP equipped units (Table 5-10~~Table 5-15~~). However, brominated PAC achieved total mercury removal of 95% at parametric tests conducted at Larmie River. TOXECON™ and Mer-Cure™ have also achieved mercury removal of over 90% in parametric tests conducted at Presque-Isle and Larmie River, respectively.

Table 5-10~~15~~. Maximum mercury removal by technology for subbituminous burning plants.

Technology	Sorbent	Unit	APCD	Sorbent Injection rate (lbs/Mmacf)	Test type	% Total Hg removal	Source
ACI	PAC (DARCO™ Hg)	Meremec-1	LNB, SOFA, cs-ESP	9.5	Parametric	72%	Sjostrom (Dec. 2008)
ACI	PAC (DARCO™ Hg)	Holcomb	FF	5.8	Parametric	90%	Sjostrom (Dec. 2008)
TOXECON II™	Brominated PAC (DARCO™ Hg-LH)	Independence-1	cs-ESP	5	Long term	80%	Sjostrom (Aug. 2008)
ACI	Brominated PAC (DARCO™ Hg-LH)	SDA, cs-ESP	SDA, cs-ESP	6	Parametric	95%	Sjostrom (Dec. 2008)
ACI	Brominated PAC (DARCO™ Hg-LH)	Holcomb	SDA, LNB, FF	1.2	Long term	91%	Sjostrom (Dec. 2008)
TOXECON™	Brominated PAC (DARCO™ Hg-LH)	Presque-Isle	hs-ESP, polishing FF	2.5	Parametric	95%	Derenne et al. (2009)
MER-CURE™	MER-CLEAN™ 8	Laramie R.	SDA, cs-ESP	2	Parametric	95%	(Sjostrom Dec 2008)

Standon-1 achieved total mercury removal of 74% using un-enhanced PAC (Table 5-11~~Table 5-16~~). Mercury removal of over 80% has been reported at Leland Olds Unit 1 when sorbent enhancement additive SEA1 was combined with un-enhanced PAC. Stanon Unit 10 achieved total mercury removal of over 90%, but this facility uses a fabric filter for particulate matter control. Alstom's Mer-cure™ system used its proprietary Mer-Clean™ sorbent at parametric testing conducted at Leland Olds Unit 1.

Table 5-11~~16~~. Maximum mercury removal by technology for lignite burning plants.

Technology	Sorbent	Unit	APCD	Sorbent Injection rate (lbs/Mmacf)	Test type	% Total Hg removal	Source
ACI	PAC (DARCO-Hg)	Stanton-1	cs-ESP	8	Parametric	74%	Jones et al. 2006
ACI + Additive	PAC (DARCO-Hg)	Leland Olds-1	cs-ESP	9 (3.4*)	Parametric	85%	Wocken et al. 2009
ACI	Brominated PAC (DARCO™ Hg-LH)	Stanton-10	SDA, FF	1.1	Parametric	91%	Wocken et. al. (2009)
MER-CURE™	MER-CLEAN™ 8	Leland Olds-1	cs-ESP	2.5	Parametric	95%	Jones et. al (2007)
* Injection of $CaCl_2$							

5.4 Ratio of cost to capture efficiency

The costs per kg of mercury captured are highest for bituminous fired units due to the lower average mercury level in bituminous coals fired by Canadian utilities, relative to the other two coal grades. For Scenario 1 the most cost effective mercury removal method identified at the 70% recovery level is Mer-cure™ followed by activated carbon injection plus oxidizing coal additive. ACI plus oxidizing coal additives is also least expensive at 80% mercury capture. Only two technologies were identified that can potentially remove up to 95% total mercury in bituminous ranked coals TOXECON™ and Mer-cure™ TOXECON™ may be more cost effective at high levels of mercury removal since lower sorbent consumption requirements offset the additional capital cost of installing the polishing baghouse (Table 5-12~~Table 5-17~~).

Table 5-12~~17~~. Scenario 1 (220 MW bituminous burning unit) - cost per MWh of energy produced.

	70%	80%	95%
ACI	$1.66	$2.41	#VALUE!
BACI	$1.54	$2.07	#VALUE!
ACI + Pff	$2.44	$2.44	$2.44
TOXECON II	Not estimated	Not estimated	Not estimated
ACI + ADDITIVES	Not estimated	Not estimated	Not estimated
TOXECON + ADDITIVES	$2.63	$2.66	Not estimated
MER-CURE	$1.94	$2.59	$3.49

For subbituminous ranked coals, Alstom's Mer-cure™ technology appears the most cost effective technology for 70% and 95% levels mercury removal, while the use of powdered activated carbon plus sorbent enhancement additive is the least costly option for 80% mercury removal (Table 5-13~~Table 5-18~~). It should be noted that these two techniques have only been subject to limited testing. By contrast, the estimated figures for conventional and brominated ACI may be considered more reliable owing as they reflect average cost factors based on a number of units that use this technology. Note that at high levels of mercury removal, TOXECON™ is more cost effective than using a brominated carbon sorbent with ESP, due to the much lower sorbent loading requirement.

Table 5-13~~18~~. Scenario 2 (400 MW subbituminous burning unit) - cost per kg of mercury captured.

	70%	80%	95%
ACI	$1.31	Not estimated	Not estimated
BACI	$0.50	$0.71	$1.66
ACI + Pff	$1.33	$1.34	$1.34
TOXECON II	$0.89	$1.28	Not estimated
ACI + ADDITIVES	$0.49	$0.59	Not estimated
TOXECON + ADDITIVES	$1.44	$1.47	Not estimated
MER-CURE	$0.35	$0.38	$0.57

Mer-cure™ is estimated as the lowest cost technology for lignite-burning units, owing to the much lower sorbent loading rates associated with this system relative to other methods of mercury removal (Table 5-14~~Table 5-19~~). These estimates should be interpreted with caution, as they are based on parametric testing only. By comparison, oxidation additives in association with ACI have been more extensively tested at lignite units, and appear cost effective at up to 80% mercury removal. Up to 95% levels of mercury removal have also been demonstrated at a lignite burning facility through the use of TOXECON™.

Table 5-14~~19~~. Scenario 3 (180 MW lignite burning unit) - cost per kg of mercury captured.

	70%	80%	95%
ACI	$1.31	Not estimated	Not estimated
BACI	$0.50	$0.71	$1.66
ACI + Pff	$1.33	$1.34	$1.34
TOXECON II	$0.89	$1.28	Not estimated
ACI + ADDITIVES	$0.49	$0.59	Not estimated
TOXECON + ADDITIVES	$1.44	$1.47	Not estimated
MER-CURE	$0.35	$0.38	$0.57

6.0 Discussion

The central objective of this project is to quantify the cost of mercury control for the Canadian coal fired power industry. The focus of Task 1 was to identify mercury control technologies most appropriate for application by the Canadian coal fired power industry to achieve nominal mercury removal targets of 70%, 80%, and 95%. The analysis was conducted for three nominal plant configurations, which were representative of Canadian units burning bituminous, subbituminous, and lignite coals. A two-stage assessment approach was used. First, a long list of technology options was assessed using a multi-criteria decision model that considered commercial, performance, and cost criteria. This assessment resulted in a short list of a number of technologies that were at relatively advanced state of commercial development. The economic analysis then compared the short-listed technologies based on their respective costs to achieve the target levels of mercury removal.

Several observations on the status with respect to mercury control in coal fired power plants have bearing on the conclusions and recommendations made in this report. First, the majority of mercury control technology evaluation and testing conducted in North America over the last 10 years has been under the auspices of the United States Department of Energy National Energy Technology Laboratory (U.S. DOE/NETL). While there has been some participation by Canadian units within the U.S. DOE/NETL mercury program, most of the units used in the analysis were U.S. based, largely fired by U.S. coal ranks, and utilizing plant emissions control regimes influenced by U.S. federal and state regulatory regimes. While there are many similarities between U.S. and Canadian based plants there are also differences, coal rank being an important example, which call for caution in developing an economic assessment of the cost of mercury control in Canada based substantially on U.S. data.

A related consideration is the variation in performance of the same technology, when applied at different plants. Differences in coal grade, air pollution control device configuration, boiler design and plant operating conditions will influence the cost and effectiveness of mercury control equipment. Estimates of cost and performance figures presented in Section 5 are based on simple averages of plants burning similar coal ranks and grades and employing similar air pollution control equipment as the characteristics of the hypothetical facilities described in the Reference Scenarios. In particular, test data suggests there may be considerable variation in sorbent injection rates required to achieve a stated level of mercury control between units that share similar characteristics. As sorbent consumption is the largest variable cost item in units employing sorbent injection systems, prudence suggests that conclusions made based on average consumption figures should be qualified with an error band that accounts for the variability in injection rates.

A third observation relates to the overall state of development of mercury control technology. The industry is still in a developmental state, characterized by having numerous technology options still in a developmental or early commercialization state and only a few that have been implemented on a commercial scale, where commercial scale use means that long term performance and cost data are available. Thus, when recommending between technology options one must not only consider apparent technical and economic performance but also the "weight of evidence" that supports those figures. Conclusions based on long term testing for more than one unit may likely more be representative than those based on long term testing at a single unit only, while long term testing is likely more indicative of permanent performance than parametric testing.

Similarly, there was considerable variation in availability and quality of economic data between different technology options. At one end of the scale, cost estimates for sorbent injection systems, and to a degree, sorbent injection plus a polishing fabric filter are supported by numerous unit specific technical and economic evaluations, as well as surveys of technology adopters conducted by the United States Government Accountability Office (U.S. GAO). Thus, cost and performance estimates derived for these technologies, while subject to numerous unit specific factors, at least are based on a reasonably strong data set.

In contrast, data and literature on several technologies are limited, warranting caution when developing generalized conclusions on cost and performance. Mer-cure^{TM} for example, is reported to offer potential for high rates (95% +) of mercury removal effectiveness at a lower cost than other technology options in plants burning subbituminous and lignite coals. Based strictly on the test results available, one might conclude that Mer-cure^{TM} would be the technology of choice for subbituminous and lignite-fired plants. However, the data set behind the Mer-cure^{TM} results appears limited. Tests conducted at four plants, summarized in Kang *et al.* (2008) , were based on the use of a modular test platform rather than permanently installed equipment, and it is uncertain that the very promising test results could be reproduced under long term plant operating conditions. As well, there is limited hard data on equipment and sorbent costs supporting the economic case for Mer-cure.^{TM} Thus, while the Mer-cure^{TM} system may be worth considering as a means of lowering the cost of mercury control, it is recommended that the baseline cost assessment be based around technologies for which there is a richer data set.

6.1.1 Scenario 1 215 MW, 70% capacity factor, bituminous coal

Scenario 1 represents a hypothetical unit in Nova Scotia, burning eastern bituminous coals, and equipped with a cold side electrostatic precipitator for particulate matter control. Nova Scotia units import a large proportion of the coal fired at their facilities and thus could potentially employ coal blending as a means of reducing mercury emissions. However, coal blending alone would be insufficient to achieve 70% mercury removal due to the limited ability of cs-ESP in removing oxidized mercury. As well, unit operators need to consider potential trade-offs between a variety of emission and performance related objectives (including SO_2 and NO_x emissions) thus, possibly reducing the effectiveness of coal blending as a stand--lone tool for mercury emissions control.

Eastern bituminous coals sold on the open market are typically washed by the mine operator, in order to reduce both the mineral fraction and sulphur content. Given the limited potential to remove mercury through blending suggests that the minimum 70% target cannot be achieved without resorting to mercury-specific technologies. An exception to this conclusion is found in the case of the Maxim Power's H.R. Milner Plant in Grand Cache, Alberta, which burns washed bituminous grade coal. The Milner plant is equipped with a fabric filter baghouse, enabling it to achieve total mercury removal of over 85% without employing mercury specific control technology.

A number of technology options have been shown to remove at least 80% of total mercury from bituminous coals, including PAC, brominated PAC, Mer-Cure^{TM}, PAC and TOXECON^{TM}. As the 70% to 80% mercury removal target can likely be achieved without the need for a polishing filter fabric the technology choices at these levels of mercury removals would focus on the most cost optimal combination of oxidation and sorbent removal technology.

Activated carbon injection using a brominated-PAC is estimated as the most cost effective technology for achieving 70% to 80% total mercury in a bituminous burning unit. Oxidizing agents have not been widely tested in bituminous plants. Mer-Cure^{TM} has been tested at only one bituminous-fired unit – while it achieved high reported levels of mercury removal, sorbent consumption rates were also high, likely rending the process uneconomical in comparison to a conventional injection system using brominated PAC.

Mer-Cure^{TM} and TOXECON^{TM} (activated carbon injection plus polishing fabric filter) were the only technologies identified as having removed over 95% total mercury in bituminous burning facilities. Of the two technologies, Mer-Cure^{TM} would likely require much lower capital expenditure. However, based on limited industry testing, a relatively high level of sorbent injection is required using to Mer-Cure^{TM} to achieve 95% mercury removal. Therefore, the TOXECON^{TM} configuration is the recommended benchmark technology for the 95% mercury removal target.

Units that sell their fly ash would incur additional disposal cost and forgone revenue if they switched to BACI for mercury control. However, for Scenario 1, the estimated amount of revenue foregone and added disposal cost would not justify adding a polishing fabric filter, assuming target mercury capture of 70% to 80%. Toxecon II^{TM} may be a cost effective means of maintaining fly ash sales at the 70% mercury capture level, though the effectiveness of this technology for bituminous burning units has not been evaluated.

6.1.2 Scenario 2 400 MW, 70% capacity factor, subbituminous coal

Mercury control technologies have been most widely tested on units that burn subbituminous grades of coal. However, such tests have been conducted on plants burning Powder River Basin coals, which have several qualitative differences to coals typically burned by the typical "Albertan" subbituminous burning unit, employing cs-ESP as PM control, which served as the basis for the hypothetical Scenario 2 unit.

Coal blending and washing were not identified as effective strategies for reducing mercury emissions from subbituminous coals. While partial blending subbituminous coal with small quantities of higher halogen western bituminous coals has been shown to result in native mercury capture of over 70% in a unit equipped with a fabric filter (source), this level of mercury removal is generally not achievable in units that use cs-ESP for PM control. Coal washing would not likely be an economic method for removing mercury in Albertan subbituminous coals as such coals feature low pyritic mineral levels, and therefore would not benefit from conventional gravimetric separation technologies.

A number of technology options have been shown to remove at least 80% of total mercury from subbituminous coals, including PAC, brominated PAC, PAC plus coal additives (oxidants), Mer-Cure™, TOXECON™ and TOXECON™ II. As the 70% to 80% mercury removal target can likely be achieved without the need for a polishing filter fabric, the technology choices at these levels of mercury removal would focus on the most cost optimal combination of oxidation and sorbent removal technology.

Activated carbon injection using Mer-Cure™ was found to be the most cost effective technology for achieving 70% to 80% total mercury in subbituminous burning units, followed by PAC plus coal additive, then brominated PAC (BPAC). As discussed above, Mer-Cure™ has been demonstrated to remove high levels of mercury at low sorbent consumption rates for subbituminous coal grades, but there has been only limited testing, no identified commercial installations, and limited economic data for which to conduct a cost analysis. By contrast the mercury removal effectiveness, as well as cost estimates for ACI based on BPAC are supported by a relatively rich data set. As well, ACI using BPAC is the technology of choice by many U.S. and Canadian subbituminous burning units that have, or are in the process of installing mercury control technology. Therefore, it is recommended that ACI based on BPAC be the benchmark technology for evaluating the cost of achieving 70% to 80% mercury control for Canadian subbituminous burning units. Brominated PAC, Mer-Cure™ and TOXECON™ (activated carbon injection plus polishing fabric filter) have all been reported to achieve over 95% total mercury in subbituminous burning facilities during parametric testing.

If the unit is selling fly ash, then the use of sorbent injection systems could result in foregone ash sales and additional ash disposal cost. Assuming that the unit foregoes ash sales based on 50% of the quantity of fly ash generated each year, ash sales price of $21/MT and ash disposal cost of $20/MT, then the unit would incur and additional $4.1 million in costs and forgone revenue each year. In this case, the lowest cost technology is TOXECON II™, which allows for recovery of 70% to 80% of fly ash, and has been proven effective at collecting up to 80% of mercury in units burning subbituminous coals. While a polishing fabric filter plus ACI combination (i.e. TOXECON™) results in a higher proportion of saleable fly ash, the capital cost of TOXECON™ renders it not economically competitive at the 70% mercury recovery level. TOXECON II™ has been shown effective at up to 80% total mercury removal, though it has been subject to only limited commercial testing. At the 95% level of mercury removal, TOXECON™ is the recommended benchmark technology for units that sell a proportion of their fly ash.

6.1.3 Scenario 3 170 MW, 70% capacity factor, lignite coal

The situation regarding natural endowment from provincial coal fields is dominant in lignite facilities, which means that the substitution and blending options are not likely to meet decision making criteria for these facilities. As with subbituminous grades, coal washing is generally not considered an economically viable method of mercury removal for lignite coals.

The technology choices available for lignite fired facilities are comparable to those burning subbituminous coals, though the breadth of commercial testing has been more limited. At the 70% to 80% level of mercury removal, Mer-Cure™ has been demonstrated to be the lowest cost technology option, followed by ACI plus oxidation additives, and then brominated PAC. As with bituminous and subbituminous grades, there are limited data available on Mer-Cure™, so, while the technology appears promising, it is not recommended as the benchmark technology for the industry cost analysis. BPAC and PAC plus oxidation additives have been subject to more extensive testing in lignite facilities. As test results indicate PAC plus oxidation additives are the most cost effective of these two technologies, it is recommended as the benchmark technology for the industry cost analysis. Only TOXECON™ AND Mer-Cure™ have demonstrated mercury removal of 95% or more in lignite burning plants.

If the unit is selling fly ash, then the use of sorbent injection systems could result in foregone ash sales and additional ash disposal cost. Assuming that the unit foregoes ash sales based on 50% of the quantity of fly ash generated each year, ash sales price of $21/MT and ash disposal cost of $20/MT then the unit would incur and additional $2.3 million in costs and forgone revenue each year. This level of additional operating cost would justify an investment in a polishing fabric filter at the 70% mercury removal level.

7.0 Conclusions and Recommendations

7.1 Conclusions

- Coal blending can improve mercury capture by existing air pollution controlled devices, by increasing halogen content of low grade coals thus enhancing oxidation from elemental to oxidized mercury. Benefits are limited by the effectiveness of existing APCD in removing oxidized mercury, which is limited to about 20% to 40% for units equipped with cs-ESP and no flue gas desulphurization. Due to high transportation costs, blending is not economically attractive compared to other methodologies for enhancing mercury oxidation in as-burnt coal such as oxidation additives.
- Bituminous coals are generally washed at the mine site, prior to shipment to a power station. Washing removes some of the mercury bound within the mineral (pyrite) fraction of the coal. Subbituminous and lignite coals are not typically washed prior to use, as they are generally consumed at the "mine mouth." While there is limited economic data available on the cost of coal washing, it is generally regarded as an uneconomic means of mercury removal in low grade coals.
- Technologies that involve injection of powdered activated carbon sorbent are the most widely tested and adopted in North America. Variations of activated carbon injection (ACI), include the use of halogenated sorbents, coal additives, sorbent enhancement additives, and injection configuration. ACI technologies can remove up to 90% of total mercury for bituminous, subbituminous, and lignite fired units, equipped with cold-side electrostatic precipitators (cs-ESP) and no SO_2 control.
- Higher levels of total mercury capture (i.e. over 95%) have been demonstrated in units equipped with ACI plus a polishing fabric filter baghouse (i.e. the TOXECON™ configuration). The Mer-cure™ configuration has also demonstrated over 95% mercury removal in parametric testing.
- The addition of a wet flue gas desulphurization (w-FGD) system for SO_2, control, in combination with a selective catalytic reduction (SCR) unit for NO_x control can result in co-benefit reduction in high co-benefit mercury capture. However, due to the high capital cost of installing these systems, they are not considered economically viable as stand alone mercury control technologies.
- ACI approaches are the most cost effective method of achieving moderate (70% to 80%) levels of mercury control in bituminous, subbituminous, and lignite based systems.
- Estimated capital costs for ACI systems range from $2.2 million to $2.4 million, including direct and indirect installation costs and mercury continuous emissions monitoring system (CEMS). Capital recovery for ACI systems accounts for a low proportion of annualized operating costs (5% to 15%, depending on coal grade and percentage mercury removal).
- Sorbent consumption accounts for the largest operating cost component for systems employing ACI. Sorbent consumption is a function of plant size, coal grade, native mercury removal of APCD, sorbent properties (including whether halogen enhanced), use of coal oxidation additives or sorbent enhancement additives, and configuration of sorbent injection system, and target mercury removal.

- Estimated capital cost for installation of a polishing fabric filter as well as an ACI system is estimated at $24 million, inclusive of installation, indirect costs, and CEMS. While the use of a pFF enables plants to reduce their sorbent consumption for a given amount of mercury removal, because of its relatively high capital cost, installing a polishing fabric filter is generally not cost effective at moderate to medium (70% to 80%) levels of mercury removal, when a plant does sell its fly ash.
- As PAC contamination can render fly ash unsellable, if a unit sells a large proportion of its fly ash then ash sales revenue (and added disposal cost) become an important consideration in mercury control technology selection. Therefore, adding a polishing fabric filter baghouse may be justified when the sum of forgone ash sales revenue plu added disposal cost exceeds the annualized capital cost of a polishing fabric filter baghouse ($2.5 to $3.0 million).
- Injection of PAC within the later stages of a cs-ESP unit (i.e. TOXECON II^{TM}) preserves about 70% of fly ash for potential sale, while achieving up to 80% total mercury removal. As TOXECON II^{TM} does not require the use of a baghouse, it is cost competitive alternative to TOXECON^{TM} when fly ash sale is important.

7.2 Recommendations

The following technology combinations are recommended for consideration in Task 2 of the project. These recommendations are based on several factors, including commercial maturity and availability, technology effectiveness, potential for adjustment over a range of mercury control targets, capital and operating cost, balance of plant considerations, and mercury fate and disposal.

7.2.1 Bituminous fired plants (Scenario 1)

The recommended benchmark technology for cost analysis of bituminous fired units with targeted mercury removal of 70% to 80% is activated carbon injection (ACI), using a brominated powdered activated sorbent. Other technology combinations, including oxidation additives plus unenhanced PAC may be cost competitive to the BACI option, but they have not been as widely tested.

To achieve 95% mercury removal the recommended approach for bituminous fired plants is a polishing fabric filter baghouse (i.e. the TOXECON^{TM} configuration). While high levels of mercury removal have been achieved through modified ACI approaches (i.e. Mer-Cure^{TM}), based on limited test data, the TOXECON^{TM} configuration is more cost effective.

Units that sell their fly ash would incur additional disposal cost and forgone revenue if they used BACI for mercury control. However, for Scenario 1, the estimated amount of revenue foregone and added disposal cost would not justify adding a polishing fabric filter, assuming target mercury capture of 70% to 80%. TOXECON II^{TM} may be a cost effective means of maintaining fly ash sales at the 70% mercury capture level, though the effectiveness of TOXECON II^{TM} in bituminous burning units has not been evaluated.

7.2.2 Subbituminous fire plants (Scenario 2)

The recommended benchmark technology for cost analysis of bituminous fired units with targeted mercury removal of 70% to 80% is activated carbon injection (ACI), using a brominated powdered activated sorbent. Other technology combinations, including oxidation additives plus unenhanced PAC and Mer-Cure^{TM} may be cost competitive to the BACI, but BACI is the most widely tested and implemented method for subbituminous fired plants. In practice, plants will likely optimize ACI efficiency by, for example, moving the PAC injectors from the ESP inlet to the inlet of the air preheater. However, the effectiveness of such approaches has not been documented in the literature.

For estimating the cost of 95% mercury removal in subbituminous plants the recommended approach the recommended technology is ACI plus polishing fabric filter baghouse (i.e. the TOXECON^{TM} configuration). High levels of mercury removal have also been achieved with Mer-Cure^{TM}, which would have a much lower annualized cost than TOXECON.^{TM} However, since test data proving 95% mercury removal for both technologies is limited, it is recommended the higher cost approach be selected for the cost evaluation.

Units that sell their fly ash would incur additional disposal cost and forgone revenue if they used ACI plus oxidation additives for mercury control. Depending on the quantities of fly ash sold the installation of either TOXECON^{TM} or TOXECON II^{TM} may be justified, with TOXECON II^{TM} more appropriate when only moderate (70%) levels of mercury removal are required.

7.2.3 Lignite fired plants (Scenario 3)

The recommended benchmark technology for cost analysis of bituminous fired units with targeted mercury removal of 70% to 80% is activated carbon injection (ACI) with the addition of an oxidation additive. This combination has been extensively tested and shown to be cost effective over BACI. The Mer-Cure^{TM} system may be cost competitive in lignite plants due to low sorbent injection requirements. However, this system is not recommended for cost benchmarking due to limited availability of testing and economic data.

Both TOXECON.^{TM} and Mer-Cure^{TM} have demonstrated 95% mercury removal. for both technologies is limited, it is recommended the higher cost approach be selected for the cost evaluation. Since test data proving 95% mercury removal for both technologies is limited, it is recommended the higher cost approach be selected for the cost evaluation.

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Units that sell their fly ash would incur additional disposal cost and forgone revenue if they used ACI plus oxidation additives for mercury control. Depending on the quantities of fly ash sold the installation of either TOXECON^{TM} or TOXECON II^{TM} may be justified, with TOXECON II^{TM} more appropriate when only moderate (70%) levels of mercury removal are required.

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