- Integrity – Are the reduction credits surplus, quantifiable, enforceable and permanent?
- Equity – A measure of whether the emission reductions offered for trade have the same environmental benefit as reductions required from the source.

Considering these criteria we found that emission reductions obtained from a *mercury-containing products reduction project* cannot be determined with any degree of certainty and therefore are not quantifiable and do not meet the integrity test. In addition, stack emission reductions and potential reductions from a mercury product collection program do not have the same environmental benefit, therefore there may not be equity between these reductions. Therefore the products reduction projects provisions have been removed from the proposal.

An additional equity issue relates to the difference in the precision and accuracy of measurements for a combustion source, like a coal-fired boiler, compared to measuring mercury emissions from a process source, like a chlor-alkali production plant. In the case of the coal-fired boiler mercury emissions can be determined through direct measurement in the stack. Mercury emissions from a chlor-alkali are indirectly determined by a material balance method that is less precise and accurate than a stack emission determination. Therefore in most cases we could not determine if mercury emission reductions from process sources are equivalent to reductions in mercury emissions from a combustion source. This lack of integrity and equity in the open market trading program initially proposed in the rules has caused us to strike these provisions.

We have also discovered that the amount of emission credits we expected to be created from industrial combustion sources is much less than anticipated. The removal of the requirement to have new or expanding sources obtain sufficient reduction credits to offset new mercury emissions is supported by this analysis.

The technical evaluation we have conducted (see Attachment B) demonstrates that the major utilities should be able to achieve the two-phase mercury emission reductions in this new two-step proposal without the need to rely on emission reduction credits created by sources in other sectors.

Members of the Mercury Citizen Advisory Committee and Mercury Technical Advisory Group

Mercury Citizen Advisory Committee

Members
Lloyd Eagan - Wisconsin Department of Natural Resources
Steve Hiniker - Citizens' Utility Board
Dave Hoopman - Wisconsin Federation of Cooperatives
Ann McCammon-Soltis - Great Lakes Indian Fish & Wildlife Commission
Bill McClenahan - Martin Schreiber & Associates (Forest County Potawatomi)
Scott Meske - Municipal Electric Utilities of Wisconsin
Annabeth Reitter - StoraEnso North America (Wisconsin Paper Council)
Keith Reopelle - Wisconsin's Environmental Decade
Russ Ruland - The Muskellunge Club of Wisconsin
Joe Shefchek - Alliant Energy
Jeff Schoepke - Wisconsin Manufacturers and Commerce
William Skewes - Wisconsin Utilities Association, Inc.
Kathleen Standen - Wisconsin Electric (WE Energies)
Wayne Stroessner - Random Lake Association
Eric Uram - Sierra Club Midwest Office
Jim Wise - ECCOLA – Environmentally Concerned Citizens of Lakeland Areas

Alternates
John Coleman - Great Lakes Indian Fish & Wildlife Commission
Mayor Kevin Crawford - City of Manitowoc (Municipal Electric Utilities of Wisconsin)
Marc Looze - Wisconsin's Environmental Decade
Ed Newman - Wisconsin Public Service Corp. (Wisconsin Utilities Association, Inc.)
Michele Pluta - Alliant Energy
Ed Wilusz - Wisconsin Paper Council
Mark Yeager – ECCOLA - Environmentally Concerned Citizens of Lakeland Areas

Facilitator
Bert Stitt - Bert Stitt & Associates Inc., Madison, Wisconsin

Wisconsin Department of Natural Resources Staff
Jon Heinrich
Anne Bogar
Tom Karman
Marty Burkholder

Mercury Technical Advisory Group

<u>Members</u>
Terry Coughlin, Wisconsin Electric
Harold Frank, Dairyland Power Cooperative
Bryna Goeckner, Wisconsin Electric
Scott Heinritz, Appleton Coated, Kimberly
Neil Howell, Department of Administration – Facilities Management
Abigail Jarka, Delta Institute, Chicago, Illinois
Roy Johnson, Energy Systems Associates, Oconomowoc
Martha Keating, Clean Air Task Force
Jim Loock, Public Service Commission
Edward Newman, Wisconsin Public Service Corporation
Greg Pavely, Vulcan Materials Company, Port Edwards
Michele Pluta, Alliant Energy
Robert Pond, The Laidlaw Group, Milwaukee

<u>Wisconsin Department of Natural Resources Staff</u>
Tom Karman
Anne Bogar
Marty Burkholder
Jon Heinrich

Technology and Cost Evaluation for the Mercury Rules Adopted by the Natural Resources Board in June 2003

An Assessment of
Major Utility Air Emission Control and Cost

I. Introduction

There are four electric utilities in Wisconsin that are significant sources of atmospheric mercury each emitting 100 pounds or more of mercury annually, based on historic reporting of their emissions. These four "major" electric utilities include Alliant Energy (AE), Dairyland Power Cooperative (DPC), WE Energies (WE) and Wisconsin Public Service Corporation (WPSC). This assessment concerns the projected application of control technology to determine the amount of mercury emission reductions that can be achieved from the 42 coal-fired boilers these major utilities operate. A specific "surrogate" control technology has been identified even though it is recognized that there may be other techniques that may be equally as effective in controlling mercury emissions. The surrogate technology evaluated in this assessment has been the focus of intense development by organizations recognized for their work in mercury control technology and it is likely to receive widespread application on electric utility coal-fired boilers in the near future.

This assessment considers two different applications of this technology that involve the injection of activated carbon into the exhaust gas of a coal-fired boiler. Also, in this assessment is a projected schedule for installation of this technology that considers the need for engineering and planning to ensure good mercury control equipment performance and that avoids disruption of electrical service during the installation on individual units as well as to an entire utility system.

The four major utilities have historically controlled mercury emissions by an average of 13%, resulting in annual emissions of approximately 2,400 pounds, in the five-year period from 1997 through 2001. It is expected that by 2008, based on anticipated equipment and operational changes, average mercury control will increase to approximately 19% with annual emissions of approximately 2,260 pounds from the four utilities.

The projected schedule for the installation of the surrogate technology in this assessment result in additional mercury emission reductions commencing in 2010 and culminating in 2015. Beginning in 2010 each major utility would have one of their large units, greater than 200 megawatts (MW), equipped with activated carbon injection with polishing fabric filter, one form of the surrogate technology. As a result, mercury emissions from the four major utilities would be reduced an average of 47% with the range among the utilities from 38% to 66%. In 2015, after completion of surrogate technology installation, average mercury emissions would be reduced by 88%, with little variation among the four major utilities. To achieve this level of control 17 of 42 coal-fired generation units currently operating would be equipped with the form of the surrogate technology that includes activated carbon injection with a polishing fabric filter. With a few exceptions these are units that are larger than 200 MW. The remaining 25 units, all 200 MW or less, would be equipped with the second form of the surrogate technology, activated carbon injection.

A dedicated fabric filter system maintains reuse of 95% of the fly ash generated for each unit using this surrogate technology. The activated carbon injection system alone applied to the small units result in all fly ash becoming unusable as a cement additive. Currently, the fly ash generated by the smaller units is of lower quality and generally not reused.

The estimated cost range for surrogate control technology installation for all major utilities in 2010 is between 28 to 33 million dollars per year. By 2015, the cost range increases to between 87 to 104 million dollars per year. For the residential household this results in an estimated added cost of 6 to 7 dollars per year in 2010 and 18 to 21 dollars per year in 2015. The estimated cost to the average commercial customer is 37 to 44 dollars per year in 2010 and 116 to 138 dollars per year in 2015. The average commercial customer has significantly higher electric consumption per year than the residential customer does. The estimated cost for an industrial customer is expressed in cost for every thousand dollars of net proceeds or of the value of shipped product in 1996. On this basis, the cost range is 0.28 to 0.33 dollars per $1000 net proceeds in 2010 and 0.88 to 1.05 dollars per $1000 net proceeds in 2015.

II. Estimate of Major Utility Mercury Emissions and Mercury Control

The purpose of this assessment is to determine the effectiveness and costs of using a specific technology to limit mercury emissions from coal-fired utility boilers in Wisconsin. In order to perform that assessment it is necessary to establish a fundamental understanding of mercury emissions and the level of mercury control that is being achieved by existing units at the four major electric utilities that are being considered for regulation. Included in this section is a summary of the following data that establishes a foundation for the analysis of the surrogate mercury control technology under consideration:

- Inventory of coal-fired units at the major utilities and their utilization.
- Estimate of mercury emissions and mercury control during the period 1997-2001.
- Projection of the amount of mercury emissions and level of mercury control that will be achieved by 2008 prior to installation of surrogate control technology.

Also included below is a brief summary of the current understanding of mercury emissions from utility coal combustion and the factors that affect the ability of the surrogate technology to effectively control mercury emissions.

Background for Estimating Mercury Emissions and Mercury Control

Since 1992, Wisconsin facilities emitting more than 18 pounds per year of hazardous air pollutants, including mercury, have been required to report annual emissions to the Department under chapter NR 438, Wis. Adm. Code. However, the Department's reporting requirement does not always specify the methods to calculate emissions of many of these contaminants. Emission estimates are often based on generalized and limited fuel content and emissions data. Therefore, even though reported mercury emissions data was readily available for coal-fired electric utility plants, in general, the emission estimates were inconsistent and did not always reflect the likely reduction that is occurring due to the existing control equipment.

In 1999, the electric utility industry nationwide participated in an extensive fuel and emissions testing program referred to as the Information Collection Request (ICR) required by the USEPA. The goal of the program was to investigate the relationship of mercury emissions to fuel characteristics, boiler types, and air pollution equipment. The program was conducted in two main phases. The first phase required samples to be periodically collected and tested for all solid fuels (coal, coke, tires, etc.) that were delivered during the entire year of 1999 for units over 25 MW (megawatts). This yielded a database of approximately 40,000 fuel samples specifying type of fuel, mercury content, fuel characteristics, and the origin of coal by mine location and/or seam.

In the second phase, 84 electric units were selected for testing stack emissions of mercury. The units were selected to represent a profile of boilers, fuel, and control equipment configurations found in the utility sector. The testing consisted of measuring mercury concentrations in the fuel and flue gas both before and after the existing pollution control equipment. Units tested in Wisconsin included Alliant Energy –

Columbia and Nelson Dewey; Wisconsin Electric – Pleasant Prairie and Port Washington; XCEL Energy – Bayfront.

Analysis of the second phase data indicates mercury removal is primarily a function of the fuel chlorine content and particulate control equipment (electrostatic precipitator, fabric filter, wet scrubber, etc.). The chlorine was found to be a primary agent in oxidizing the mercury to a charged form that readily attaches to a particulate. The mercury / particulate is then removed in the particulate control equipment (fabric filter, electrostatic precipitator, etc.). In general, an increased amount of chlorine results in a higher percentage of oxidized mercury and therefore higher mercury removal. Since oxidized mercury is also soluble in water, it is also removed by wet scrubber systems used for sulfur dioxide control. Other secondary factors that influenced mercury removal include fuel properties such as sulfur, calcium, and moisture content, the flue gas temperature prior to control equipment, and the mixing or contact time between the mercury and flue gas particulate.

For this assessment mercury emission control achieved by an individual unit is best determined by a specific stack test or from information derived from a test on a similar unit. This provides a better estimate of mercury control and efficiency than has been available in the past. However, few of the major utility units have performed stack tests to determine control efficiency of the existing equipment. Also, fuel properties and particulate control equipment can significantly affect any one units mercury control efficiency. The estimates for the existing control efficiency will not be conclusive until stack testing is performed for all units.

In this assessment specific stack test information is taken from those tests performed for the ICR phase II effort **(1)** or from other stack test data available to the Department. For the majority of units that do not have stack test data the control efficiency is taken from the EPRI analysis of ICR data and their estimate of mercury emissions for each coal-fired boiler in the United States **(2)**. Units smaller than 25 MW were not addressed by EPRI, however estimates were derived from their analysis. Units smaller than 25 MW included in this assessment are Dairyland Power Cooperative - Alma 1, 2, and 3, and WE Energies - County Plant 1, 2, and 3.

The mercury content of the fuel is derived from the EPRI analysis of the 1999 ICR fuel data specific for each unit **(2)**. Since the ICR fuel testing did not include units less than 25 MW the average characteristics determined by the ICR data for each fuel type was applied to these units. The fuel consumption data used in this assessment is derived from the USEPA's Acid Rain program database for units greater than 25 MW **(3)**. Fuel consumption data from the Department's Air Emission Inventory is used for the units smaller than 25 MW **(4)**.

Characterization of Major Utility Coal-Fired Boilers

Table 1- Major Utility Generation Units and Utilization, includes all units that were coal-fired boilers from 1997 to 2001. A total of 42 units at 14 different facilities were firing coal during that period (see appendices - *Table A1- Major Utility Units Firing Coal in 1997-2001, Fuel Consumption, Utilization, and Electric Generation* for a detailed listing of fuel consumption, capacity factors and electrical generation for individual units). Note that this assessment does not include mercury emissions from combustion turbines that are primarily fired by natural gas.

Table 1. Major Utility Generation Units and Utilization (1997 – 2001)

Major Utility	No. of Facilities	No. of Units	Generation Capacity			Percent of	
			Total	Units >	Units <	Units >	Units <
AE	4	9	2,143	1,733	410	81%	19%
DPC	3	7	957	750	207	78%	22%
WE	5	17	2,851	2,263	588	79%	21%
WPSC	2	9	892	337	555	38%	62%
Total	14	42	6,843	5,083	1,760	74%	26%

Major Utility Mercury Emissions and Mercury Control Efficiency for 1997 - 2001

The estimate of the average mercury emission control and total mercury emissions at major utilities for the period 1997 through 2001 is included in *Table 2 - Estimate of Mercury Control Efficiency and Emissions*. On average, the four major utilities emitted approximately 2,400 pounds of mercury per year and achieved a 13% mercury control efficiency and during this period. The equipment configuration and control efficiency for each unit in the analyses of mercury control and emissions (1997 – 2001) is detailed in the appendix (see *Table A2 – Estimated Mercury Control and Average Emissions for 1997 through 2001)*.

Table 2. Estimate of Mercury Control Efficiency and Emissions That Occurred in 1997 through 2001 (3 year averages)

Major	Existing Control			Mercury Emissions			
	1997-1999	1998-2000	1999-2001	1997-1999	1998-2000	1999-2001	Analysis
AE	11%	11%	10%	687	671	653	687
DPC	23%	22%	22%	188	192	192	192
WE	12%	12%	12%	1,305	1,297	1,299	1,299
WPSC	16%	16%	16%	235	237	236	236
Average/Total	**13%**	**13%**	**13%**	**2,422**	**2,405**	**2,387**	**2,415**

Note: Shaded area denotes fuel consumption case assumed for each utility in the analysis.

Determination of Growth in Fuel Consumption

For this assessment the highest consecutive three-year average fuel consumption over a five-year period (1997-2001) is the basis for determining the amount of mercury each major utility is capable of emitting. For Dairyland Power Cooperative (DPC), WE Energies (WE) and Wisconsin Public Service Corporation (WPSC) this is the 1999 to 2001 three-year average. For Alliant Energy, 1997 to 1999 is the highest three-year average. As a result of this evaluation, no growth in fuel consumption is assumed to occur from existing coal-fired units at the major utilities.

Table 3 – Percent Fuel Consumption of Maximum Potential, indicates that overall consumption declined 1.2% based on the three-year averages of unit capacity utilization from 1997 through 2001 (the most recent years of available fuel consumption certified data). Three major utilities, DPC, WPSC and WE had slight increases, from 0.3 to 1.1%. Alliant Energy had a large decline of 5.1% in consumption, primarily due to less utilization of units under 200 MW.

Little or no growth is indicated by the analysis of fuel consumption over the historic five-year period. It is normal for fluctuations to occur on a year-to-year basis from variations in weather and other factors. Three-year averaging is used to minimize variance due to these factors. Selecting the highest three-year average in the analysis further mitigates the impact that a year of low fuel consumption would have in determining normal consumption.

Table 3. Percent Fuel Consumption of Maximum Potential (1997 – 2001)

	97-99	98-00	99--01	% Change 199 to 2001
Units > 200				
AE	77%	77%	76%	-1.4%
DPC	74%	74%	75%	1.7%
WE	87%	87%	88%	0.5%
WPSC	87%	86%	85%	-2.2%
Total	82%	82%	82%	-0.2%
Units < 200				
AE	48%	42%	37%	-28.9%
DPC	45%	48%	44%	-3.8%
WE	47%	48%	47%	-1.1%
WPSC	77%	79%	79%	3.5%
Total	55%	55%	52%	-5.1%
All Units				
AE	70%	69%	67%	-5.1%
DPC	67%	68%	68%	0.9%
WE	77%	77%	77%	0.3%
WPSC	81%	82%	82%	1.1%
Total	74%	74%	73%	-1.2%

Notes:
-Shaded area indicates high fuel consumption years for each major utility.
-Capacity utilization based on federal acid rain program fuel consumption data and Wisconsin DNR air emissions inventory.

Units over 200 MW (megawatts) operated by WPSC and WE have high consumption levels 85% and 88%, respectively, from their maximum potential. Typically, it is expected that the highest utilization that these units could achieve is no more than 90% to 95% considering maintenance requirements and system management requirements. As units age, this potential capacity is not expected to increase unless there are major equipment upgrades or significant operational changes. Therefore these units are considered to be near their maximum capacity utilization. For DPC and AE, their units over 200 MW had fuel consumption levels of 75% and 77%, respectively, indicative of the potential for growth. However, their fuel consumption data for the period 1997-2001 does not indicate a trend toward growth.

Units below 200 MW do not show a trend toward increased utilization. The majority of these units are nearing retirement and their operation levels have reached their peak (see appendices *Table A1 Major Utility Units Firing Coal in 1997-2001, Fuel Consumption, Utilization, and Electric Generation*). It is expected that new capacity or re-powering will replace aging small unit utilization and account for future growth. This is demonstrated by WE's re-powering of their Port Washington Generating Station and the conversion of AE's Rock River Generating Station to natural gas. In addition, three of the major utilities are seeking approval or developing plans for adding significant new coal-fired capacity to address growth.

Major Utility Mercury Emissions and Mercury Control Efficiency for 2008

Table 4 - Estimate of Mercury Control Efficiency and Emissions by 2008, summarizes the anticipated mercury control efficiency and mercury emissions in 2008 for each major utility. *Table A3 – Estimated Mercury Control and Emissions for 2008,* in the appendices, provides the detailed information used to arrive at these averages. These estimates establish the foundation for determining the incremental improvement in overall mercury control efficiency that will be achieved from the installation of the surrogate mercury control technology defined in Section III.

Based on this analysis major utilities are expected to achieve an average mercury control efficiency of 19% and emit 2,259 pounds of mercury per year in 2008. Anticipated mercury control efficiency varied from 15% to 37% and increased for each major utility over current levels (see Table 2) with the exception of Dairyland Power Cooperative. These increases are the result of a recently installed fabric filter at Wisconsin Public Service Corporation – Weston 3 unit, repowering of the WE Energies – Port Washington Station, and conversion of Alliant Energy – Rock River Station to natural gas.

Table 4. Estimate of Mercury Control Efficiency and Emissions by 2008

Major	Anticipated Efficiency	Mercury (lbs/yr)
AE	15%	654
DPC	22%	192
WE	17%	1,227
WPSC	37%	178
Average/Total	**19%**	**2,259**

III. Surrogate Mercury Control Technology

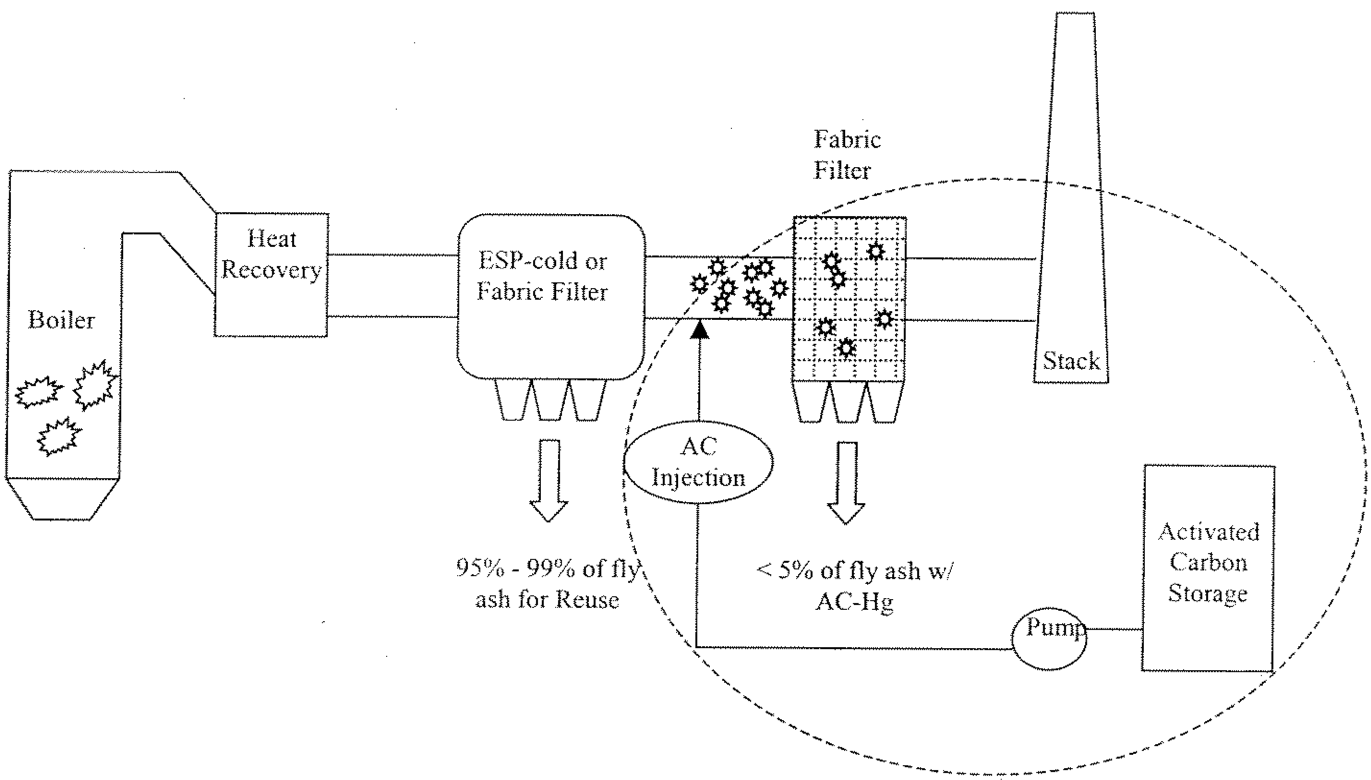
This section includes a determination of the level of mercury emission control that the surrogate technology can achieve. Two configurations of the surrogate technology are considered. One configuration, activated carbon injection with dedicated polishing fabric filter system (AC/FF), is deemed suitable for installation on units where a long-term capital investment is appropriate. These are generally newer larger units (greater than 200 MW) that have significant use. The second configuration is activated carbon injection (AC) alone upstream of the existing particulate control equipment. The second configuration is more appropriate for older smaller units that are declining in use. Also, provided is a description of the two configurations and rationale for selecting which configuration each of the 42 major utility coal-fired boilers should receive.

Activated Carbon Injection / Polishing Fabric Filter System Configuration (AC/FF)

This configuration controls mercury through the injection of activated carbon into the flue gas stream after the existing particulate control equipment but prior to a newly installed polishing fabric filter as shown in schematic 1. The injected carbon adsorbs both the ionic and elemental mercury and forms a mercury / activated carbon particulate that is captured in the polishing fabric filter. This configuration requires the installation of activated carbon storage, injection equipment, and a polishing fabric filter system.

This configuration minimizes the impact on the reuse of fly ash. According to EPRI, 95% of more of the original fly ash is collected in the existing particulate control equipment as depicted in schematic 1 and therefore retains its reuse potential **(5)**. The remaining 5% of fly ash becomes contaminated with activated carbon and is collected downstream in the polishing fabric filter along with the captured mercury.

A 90% mercury control efficiency measured from the fuel input to the final exhaust gas is assumed for all units regardless of existing pollution control equipment or fuel type. This level of control is achievable based on test results for fabric filter mercury removal, with and without activated carbon injection. According to ICR data, fabric filters demonstrate control efficiencies from 48% to 86% for units firing sub-bituminous coal and 35% to 99% for units firing bituminous coal **(1)**. The high removal rates are attributed to the fabric filters producing a high level of contact between the fly ash and mercury as the flue gas passes through the filter cake. The addition of activated carbon prior to the fabric filter enhances this process with a compound that readily absorbs both ionic and elemental forms of mercury.



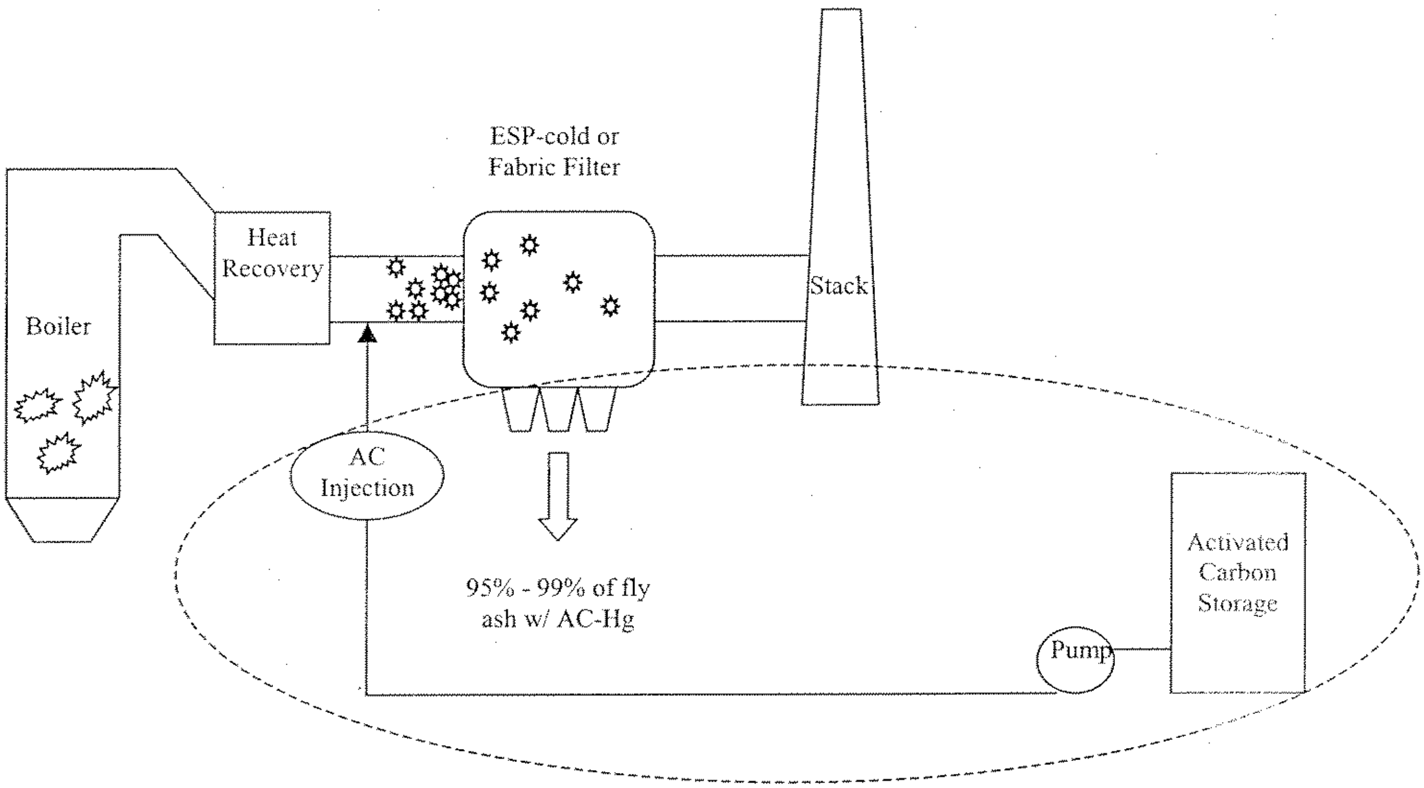
Schematic 1 - Activated Carbon Injection / Polishing Fabric Filter System (AC/FF)

The United States Department of Energy (USDOE), USEPA, EPRI and participating utilities have conducted pilot testing and one full-scale test of activated carbon injection prior to an existing fabric filter. The pilot scale test results, as compiled by EPRI **(2)** demonstrated control efficiencies ranging from 70% to greater than 90%. A control efficiency of 80% was maintained over an extended period without any evident adverse plant operation impacts at an activated carbon injection rate of 2 pounds per million cubic feet per minute of exhaust gas.

Based on this testing EPRI has stated that the 90% control efficiency is achievable with this configuration however, additional testing at 2 to 4 sites involving different coals is necessary to perfect design and operation to achieve this level **(5)**. This could be completed over a three-year period. This pilot testing has also demonstrated that given proper contact time the carbon adsorbs both ionic and elemental mercury and therefore its use is not limited by fuel type (sub-bituminous vs. bituminous). These results indicate that proper design and optimization would achieve the expected 90% or greater control efficiency for this configuration across all fuel types.

Activated Carbon Injection Configuration (AC)

In this configuration, activated carbon is injected upstream of an existing particulate control device where the mercury / activated carbon particulate is removed (schematic 2). This configuration can be applied to units with an existing cold-side electrostatic precipitator or a fabric filter. In front of the existing particulate control equipment activated carbon enters into the flue gas stream adsorbing both ionic and elemental mercury.



Schematic 2 - Activated Carbon Injection (AC)

This configuration is appropriate for smaller less utilized generation units. The majority of units less than 200 MW at the major utilities are in this category (see *Table 1- Major Utility Generation Units and Utilization*). In addition, these units do not have a remaining life expectancy beyond that of a newly installed fabric filter and thus may be poor candidates for a large capital investment. This configuration only requires installation of activated carbon storage and injection equipment. It is significantly less capital and equipment intensive than the AC/FF configuration.

Although the fly ash generated at these units will now contain activated carbon and mercury, no impact to fly ash reuse is assumed in the cost analysis. These units, in general, produce a lower quality fly ash that is typically disposed of in a landfill. In some cases it has been used for fill or re-burned to capture lost fuel value, but these options are not consistently available. For a system with an existing electrostatic precipitator the injection of activated carbon is expected to achieve 60% mercury control efficiency. Full-scale testing at WE's Pleasant Prairie Power Plant demonstrated 60% mercury control efficiency at an activated carbon injection rate of 5 pounds per million actual cubic feet per minute with no noticeable plant operation impacts **(5)**.

In their analysis, EPRI believes that the AC configuration requires an additional 6 months to 2 years of testing to determine AC effectiveness on a range of fuel types and particulate control systems **(5)**. It should also be noted that the electrostatic precipitator at WE - Pleasant Prairie has been converted from a hot-side to a cold-side unit, thus physically, the precipitator is oversized which creates more retention time and contact surface than a conventional cold-side unit configuration.

With an existing fabric filter, this configuration is assumed to achieve 80% control efficiency at an activated carbon injection rate of 2 pounds per million actual cubic feet per minute. This control level would apply to WE's four units at their Valley Power Plant that are equipped with existing fabric filter systems.

Application of the Surrogate Control Technology Configurations to Specific Units

The AC/FF configuration is applied to units that comprise the core generation capacity at each major utility. For Dairyland Power Cooperative (DPC), WE Energies (WE) and Alliant Energy (AE) this includes all units greater than 200 MW. For Wisconsin Public Service Corporation (WPSC) this includes Weston 1, with a capacity greater than 200 MW, and Weston 2 and 3 and Pulliam 7 and 8, which are units less than 200 MW. WPSC's relies on small units to provide 62% of capacity. This is significantly greater than any of the other major utilities where small units, on average, provide only 20% of generation capacity (*see Table 1- Major Utility Generation Units and Utilization*). With the inclusion of the small units at WPSC approximately 80% of the generation capacity of each major utility would be subject to the installation of the AC/FF configuration.

The AC configuration is applied to smaller less utilized units that are expected to cease operation within the next 15 years (Refer to *Table A1 – Major Utility Units Firing Coal in 1997-2001* for unit age and capacity information for all units). *Table 5 – Application of Surrogate Control Technology Configurations*, depicts the number of units that would install configuration, AC/FF or AC, and the percent of generating capacity that each configuration would affect. The configuration that each unit is assigned can be found in the Appendices (see *Table A4 – Percent Mercury Control by Utility*).

Table 5. Application of Surrogate Control Technology Configurations

Major Utility	Threshold	AC/FF			AC		
		No. of Units	% of Capacity	% of Generation	No. of	% of Capacity	% of Generation
AE	200 MW	4	81%	85%	5	19%	15%
DPC		2	78%	86%	5	22%	14%
WE		6	79%	88%	11	21%	12%
WPSC	Weston 1,2,3 and Pulliam 7,8	5	81%	83%	4	19%	17%

IV. Surrogate Technology Installation Schedule

The surrogate technology installation schedule includes three distinct periods - technology optimization, utility planning, and design and equipment installation. In order to achieve significant mercury emission reductions a schedule that accommodates each of these periods is essential. The installation schedule established considers the benefits of allowing additional time for mercury control technology development to occur before commencing system-wide planning and design. The feasibility of mercury control must also account for the time necessary to implement significant installation of equipment across multiple units while still meeting electricity demand.

Table 6 - Assumptions and Parameters for Surrogate Technology Installation Schedule provides the time in years required for each period for each configuration, AC and AC/FF. Common to both configurations is an initial three-year period for technology optimization recommended by EPRI **(5)**. By the third year of this period it is assumed the utilities will have sufficient information to begin a two-year period of specifying system-wide technology choices and initial planning for all unit installations.

Table 6 Assumptions and Parameters for Surrogate Technology Installation Schedule

AC/FF System	Requirement
- Technology optimization	3 years
- Utility planning	2 years
- Design and installation	3 years
- Period between 1st and 2nd installati	2 years
- After 2nd installation a new unit begins operation each year	Annual

AC System	Requirement
- Technology optimization	3 years
- Utility planning	2 years
- Design and installation	1 year
- Periodic installations	Annual

The remaining periods are specific to each technology configuration. For AC/FF, this includes a three-year design and installation period for the initial installation followed by a two-year period for the second unit to begin operation at a major utility. Design of the second unit is assumed to begin in the last year of installing the initial unit. It is then assumed that design and installation can be undertaken sequentially such that one new AC/FF system will begin operating each year after the second unit installation.

Table 7. Schedule for Installing Surrogate Technology

Calendar Year	Schedule Year	AC/FF	AC
2003 - 2006	0 -3	---------------------------Full-scale testing and optimization---------------------------------	
2005 - 2007	2 to 4	---------------------------Initial utility system-wide planning--------------------------------	
2007 - 2009	4 to 6	1st unit design and installation	
2009 - 2011	6 to 8	2nd unit design and installation	
2010	7	1st unit operating	1st unit design and installation
2011	8		1st unit operating /2nd unit design and installation
2012	9	2nd unit operating	2nd unit operating
2013 - 2015	10 to 12	One new unit operating each year	One new unit operating each year

Following these assumptions results in the schedule shown *in Table 7 - Schedule for Installing Surrogate Technology*. Note that the schedule is assumed to commence beginning January 1, 2003. According to this schedule initial mercury emission reductions from the installation of surrogate technology begin in

2010. By 2015, the final mercury reduction level is achieved from the application of the surrogate technology.

The initial AC/FF system begins operation in the 7th year or in 2010. By 2015, the 12th year of the schedule, all AC/FF systems are installed. See *Table A4 – Percent Mercury Control by Utility* in the appendices for the assumed sequence of installations by unit for each major utility. It is important to note that Dairyland Power Cooperative will only need two AC/FF systems. Alliant Energy will need four AC/FF systems and these installations are complete by the 11th year or 2014. WE Energies and Wisconsin Public Service Corporation will have their last AC/FF systems operating in the 12th year or 2015.

The schedule of installation also targets the higher capacity unit first within each major utility system. AC system installation does not commence until after the initial AC/FF system for each utility is operating. This is intended to allow the maximum amount of capacity to be available while each utility is installing the AC/FF system on their largest capacity unit and to minimize any potential reliability issues.

The AC systems are not equipment intensive and can be designed and installed on annual basis. Starting in the 8th year, or 2011,each major utility begins operation of a new AC system. Only WE Energies will have these installations occurring through 2014. The sequence of AC system installations by unit for each major utility is outlined in *Table A4 – Percent Mercury Control by Utility*.

The installation schedule minimizes impacts to electric reliability. An important additional consideration is the effect on reliability caused by overlapping plant outages at several major utilities for the purpose of equipment installation. This type of reliability impact was evaluated by the Wisconsin Public Service Commission (PSC) for a potential statewide installation of nitrogen oxide (NOx) pollution control equipment. The PSC concluded that outages due to installing major equipment would not have adverse impact on electric reliability. Further, the PSC recommended that utilities submit a joint report to address coordinating installations and outages **(6)**.

In comparison, the mercury surrogate control installation schedule addresses approximately the same number of units however, the installation schedule is longer than the proposed NOx program. For the NOx program the utilities projected installing selective catalytic reduction (SCR) equipment on every major unit within a three year period. The mercury schedule assumes major equipment construction and installation over a potential eight to ten year period. The installation time is two to three years for either a SCR or a AC/FF. Therefore, electric reliability should not be an issue for the proposed surrogate mercury technology installation schedule.

V. Major Utility Mercury Control Achieved

In this section the cumulative mercury control achieved by the installation of the surrogate technology is determined. The starting point for this determination is the expected level of mercury control that is being achieved in 2008 (see Section II). The mercury control resulting from existing pollution control equipment is expected to range from 15% to 37% among the four major utilities with an overall average of 19%. *Table 8 - Percent Mercury Control*, depicts the mercury control level achieved from installation of the surrogate control technology that follows the schedule presented in Section III. The calculation of the control levels in Table 8 assume that the 2008 control level determined for a unit is replaced by the surrogate technology control level according to the detailed installation schedule in *Table A4 – Percent Mercury Control by Utility* in the appendices.

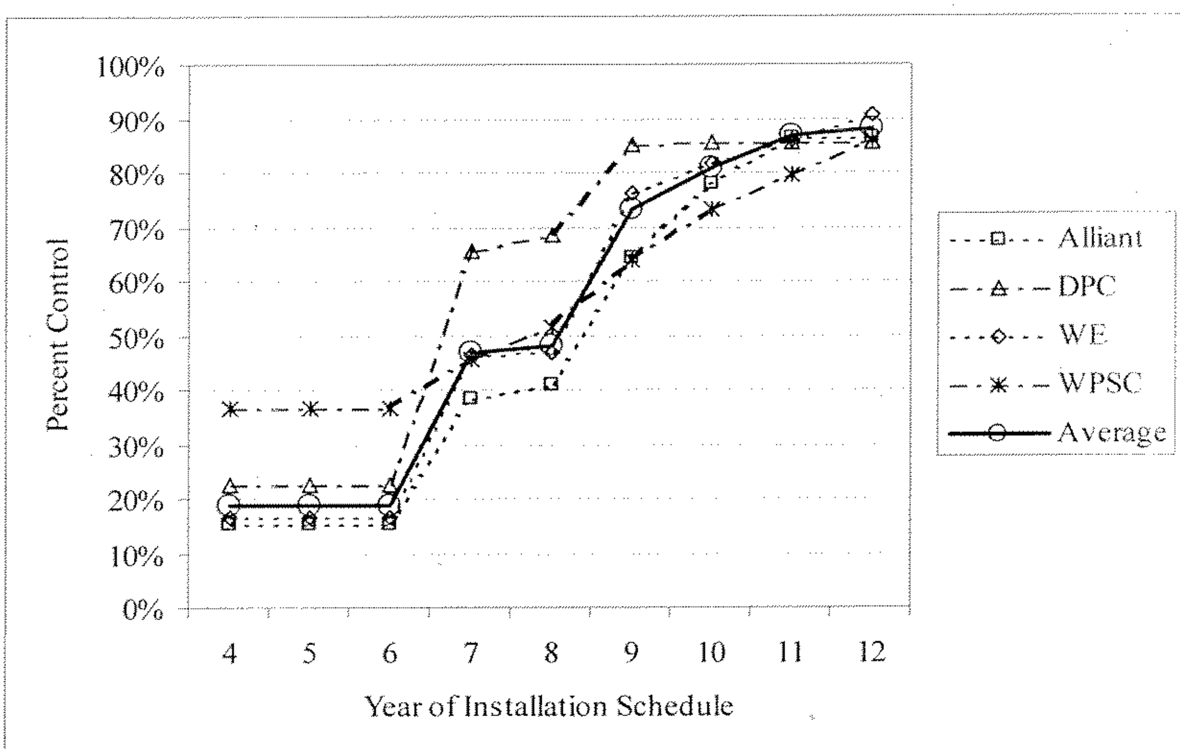
Table 8. Percent Mercury Control

	Existing Control	Existing + Surrogate Technology Control					
Major Utility	**6** 2009	**7** 2010	**8** 2011	**9** 2012	**10** 2013	**11** 2014	**12** 2015
AE	15%	38%	41%	64%	78%	86%	86%
DPC	23%	66%	69%	85%	86%	86%	86%
WE	17%	46%	47%	76%	82%	86%	91%
WPSC	37%	46%	52%	64%	73%	80%	86%
Average	19%	47%	48%	73%	81%	87%	88%

According to the proposed installation schedule, the largest uncontrolled unit of each major utility will have an AC/FF system in operation by the 7[th] year (2010). As shown in *Table 7 - Schedule for Installing Surrogate Technology*, this installation along with the existing control achieved on the remaining units results in an average 44% reduction of uncontrolled mercury emissions. The lowest reduction is 38% for Alliant Energy and the highest is 66% for Dairyland Power Cooperative.

Figure 1 - Percent Mercury Control from Existing and Surrogate Control Technology, depicts the improvement in mercury control that occurs as the surrogate control technology systems become operational. At the completion of the schedule, uncontrolled mercury emissions have been reduced by 88% from all coal-fired units operated by the major utilities during the period 1999 to 2001. In addition, each major utility has achieved at least an 86% mercury control level with the range from 86% to 91%.

Figure 1. Percent Mercury Control from Existing and Surrogate Control Technology



VI. Cost of Surrogate Control Technology

The installation schedule for surrogate control technology is outlined in *Table A4 – Percent Mercury Control by Utility* in the appendices. The estimated annual mercury control cost is the annualized cost of installing and operating the surrogate control technology that follows that installation schedule. Costs are determined for each unit based on the control parameters and additional requirements identified for each surrogate technology configuration in *Table 9 - Surrogate Control Technology Parameters*. The specific equipment cost and operation factors are listed in *Table 10 - Surrogate Control Technology Cost Analysis Factors*. These factors were obtained from the EPRI analysis of mercury control technology **(5)**, USEPA **(1)**, or consideration of other industry information **(7)**.

<u>Surrogate Control Technology Installation Parameters and Cost Factors</u>

The surrogate control technology is applied in two different configurations to all 42 units based on the distinctions summarized in *Table 9 - Surrogate Control Technology Parameters*. The configuration applied to high utilization units is activated carbon injection with a dedicated polishing fabric filter system (AC/FF). This configuration is assumed to achieve 90% control efficiency and to preserve the reuse of at least 95% of fly ash generated. The use of a dedicated fabric filter has the benefit of significantly reducing the amount of activated carbon required while still achieving high mercury control levels.

For smaller, less utilized, and older units the control configuration is activated carbon injection (AC) with an assumed mercury control efficiency determined by the existing particulate control equipment, 60% for an electrostatic precipitator or 80% for a fabric filter. The AC configuration achieves mercury control without a large capital investment in equipment that has a longer expected life than the unit.

Table 9. Surrogate Control Technology Parameters

Existing Equipment Configuration		**Surrogate Control Parameters**				**Additional Requirements**	
Category	**Existing Equipment**	**Technology**	**AC Injection Rate (lbs/mmacf)**	**Control Efficiency**	**Impact to Flyash Reuse**	**Expected Cost**	**High Cost**
Low utilization units and remaining lifetime < 15 years	ESP-coldside	AC	5	60%	none		install extra ESP field
	ESP-hotside	AC	5	60%	none	ESP converted from hotside to coldside	install extra ESP field
	Fabric Filter	AC	2	80%	none		
High utilization units with remaining lifetime > 15 years	All Units	AC/FF	2	90%	95% Flyash Reused	- 5% flyash landfilled - Either oversized fabric filter or reduced filter life	- 5% flyash disposed as hazadous waste - Both oversized fabric filter and reduced filter life

In applying the surrogate control equipment an "Expected Cost" and "High Cost" effort is identified that reflects a potential range in costs.

For example, in recognition of the electrostatic precipitator condition for the pilot test of AC at WE Energies Pleasant Prairie, installation of an extra collection field for cold-side electrostatic precipitators is considered in the high cost effort. For hot-side precipitators, affecting two units at Alliant Energy Nelson Dewey, the expected cost effort requires conversion to cold-side precipitators and the high cost effort adds an extra collection field to the conversion.

Lost revenue from fly ash are evaluated under two disposal situations, disposal in a sanitary landfill, expected cost, or disposal as a hazardous waste, high cost. Note that the Department is not anticipating that fly ash from an AC/FF system will need to be treated as a hazardous waste. Its designation here is in response to a comment on possible costs for this configuration that should be evaluated. To account for increased particulate loading from injecting activated carbon into the exhaust gas, the analysis for the expected case considers either a shortening of filter life or enlarging the size of the polishing fabric filter. For a particular application the most cost-effective approach was selected. The high cost effort considers both reduced filter life and an oversized fabric filter design.

Table 10. Surrogate Control Technology Cost Analysis Factors

Parameter	Cost Factor	Reference
Economic Analysis Factor		
Fixed charge rate	15%	5
Utility investment return rate	8%	5
Equipment life	15 years	5
Activated Carbon Injection System		
Injection and storage equipment	2$/KW	5
Annual operation and maintenance	0.4$/KW	5
Activated carbon	0.5$/lb	5
Existing Equipment Modifications		
Convert hot-side ESP to cold-side	50$/KW	5
Install extra ESP collection field	12$/KW	5
		5
Fabric Filter		
Fabric filter system	40$/KW	5
Annual operation and maintenance	2 M$/yr	5
Factor for oversizing fabric filter	10$/KW	5
Annual cost for reduced fabric filter life	0.6M$/yr	5
Flyash Impacts		
Lost revenue for cement reuse	10$/ton	1, 5, 7
Landfill disposal cost	30$/ton	1, 5, 7
Hazardous waste disposal	200$/ton	1, 5

The analysis does not include any cost for electric purchases by a major utility during the installation of surrogate control technology equipment. The installation schedule is assumed to minimize this potential impact.

The initial capital cost of equipment and installation is annualized using a fixed charge rate of 15%, recommended by EPRI for utility pollution control equipment with an expected 15 year equipment life and an 8% return on investment. Beyond 15 years, the only costs are for material consumption and operation and maintenance costs. Annual costs will increase if either the equipment life is shortened or the rate of return increases. *Table A5 – Mercury Control Costs for Application of Surrogate Control Technology*, details how annual cost accrues throughout the installation schedule for both the expected and high cost cases outlined in *Table 9.*

Cost Summary for all Major Utilities

The total annual expected and high costs for each utility are summarized in *Table 11 - Estimate of Surrogate Technology Mercury Control Cost (Million $ / Year)*. The analysis assumes the annual cost of a unit is first incurred in the year it begins operation. The ongoing annual cost peaks in the 12th year of the schedule when all surrogate control installations are operating. This is the final annual cost that continues through the life of the surrogate technology equipment. The initial annual cost for all major utilities starting in 2010 (7th year) is 28 to 33 million dollars for the expected and high cost cases, respectively. This cost represents each utility operating one AC/FF on their largest mercury-emitting unit. The final annual cost for all units operating in 2015 (12th year) is 87 to 104 million dollars for the expected and high cost cases, respectively.

Table 11. Estimate of Surrogate Technology Mercury Control Cost (Million $ / Year)

Major Utility	Schedule Year						Outgoing Years	
	2010	2011	2012	2013	2014	2015	2030	2035
	7	8	9	10	11	12	20	25
Expected Cost Scenario								
AE	8	8	16	22	26	26	26	<26
DPC	5	6	11	11	11	11	11	<11
WE	10	10	21	28	33	37	37	<37
WPSC	5	6	8	9	10	12	12	<12
Total	28	30	56	71	81	87	87	<87
High Cost Scenario								
AE	9	10	19	26	31	31	31	<31
DPC	6	7	14	14	14	14	14	<14
WE	11	12	24	33	38	44	44	<44
WPSC	6	7	10	12	14	16	16	<16
Total	33	35	66	84	96	104	104	<104

The annual cost is expected to remain constant from the 12th year through the expected life of the surrogate control equipment, 15 years. This ongoing cost is expressed under the "outgoing years" in Table 9 where the annual cost remains the same from the 12th to the 20th year. However, by the 25th year the annualized capital cost of many unit installations will be paid off and the total annual cost will begin to decrease. The increase in electricity rates from the installation of the surrogate control technology is normalized to the amount of electricity generated by all 42 coal-fired units (see appendices Table A1).

The resulting incremental cost in cents per kilowatt-hour is compiled in *Table 12 - Incremental Electricity Cost of Surrogate Control Technology (cents / kilowatt-hour)* for each utility. This shows the cost for the 47% mercury control achieved in 2010 (7th year) adds an electricity cost of 0.06 to 0.07 cents per kilowatt-hour (kWh). By 2015 (12th year) at 88% mercury control the average cost ranges from 0.19 to 0.23 cents per kWh.

Table 12. Incremental Electricity Cost of Surrogate Control Technology (cents / kilowatt-hour)

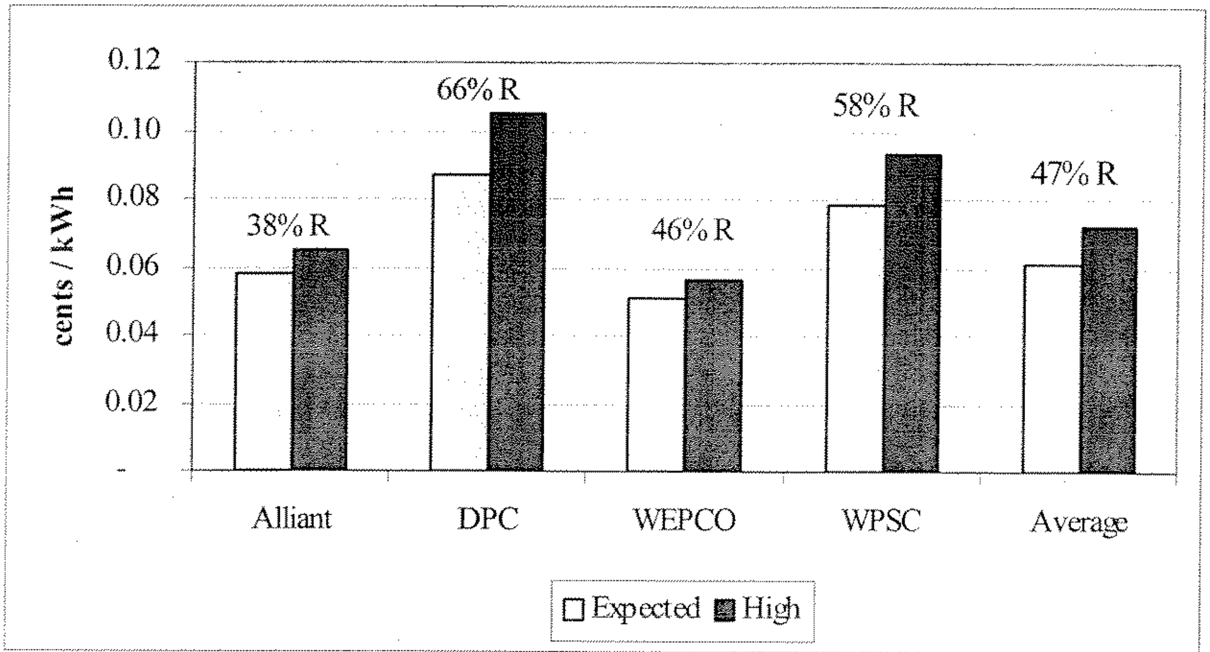
Major Utility	Schedule Year						Outgoing Years	
	2010	2011	2012	2013	2014	2015	2030	2035
	7	8	9	10	11	12	20	25
Expected Cost Scenario								
AE	0.06	0.06	0.12	0.16	0.19	0.19	0.19	<0.19
DPC	0.09	0.10	0.19	0.19	0.19	0.19	0.19	<0.19
WE	0.05	0.05	0.11	0.14	0.17	0.19	0.19	<0.19
WPSC	0.08	0.09	0.12	0.14	0.16	0.19	0.19	<0.19
Average	0.06	0.07	0.12	0.16	0.18	0.19	0.19	<0.19
High Cost Scenario								
AE	0.07	0.07	0.14	0.19	0.22	0.22	0.22	<0.22
DPC	0.10	0.12	0.24	0.24	0.24	0.24	0.24	<0.24
WE	0.06	0.06	0.12	0.17	0.19	0.22	0.22	<0.22
WPSC	0.09	0.11	0.16	0.19	0.22	0.25	0.25	<0.25
Average	0.07	0.08	0.15	0.18	0.21	0.23	0.23	<0.23

Individual Major Utility Costs

Figure 2 - Incremental Electricity Cost at the 47% Average Mercury Control Level for Surrogate Control Technology, illustrates the difference in incremental electricity cost between the major utilities in 2010. For the expected case the cost ranges from 0.05 cents/kWh for WE to 0.09 cents/kWh for Dairyland Power Cooperative. The higher cost for Dairyland Power Cooperative and Wisconsin Public Service Corporation is due to a larger portion of their system capacity being covered by the first installation as compared to Alliant Energy and WE Energies.

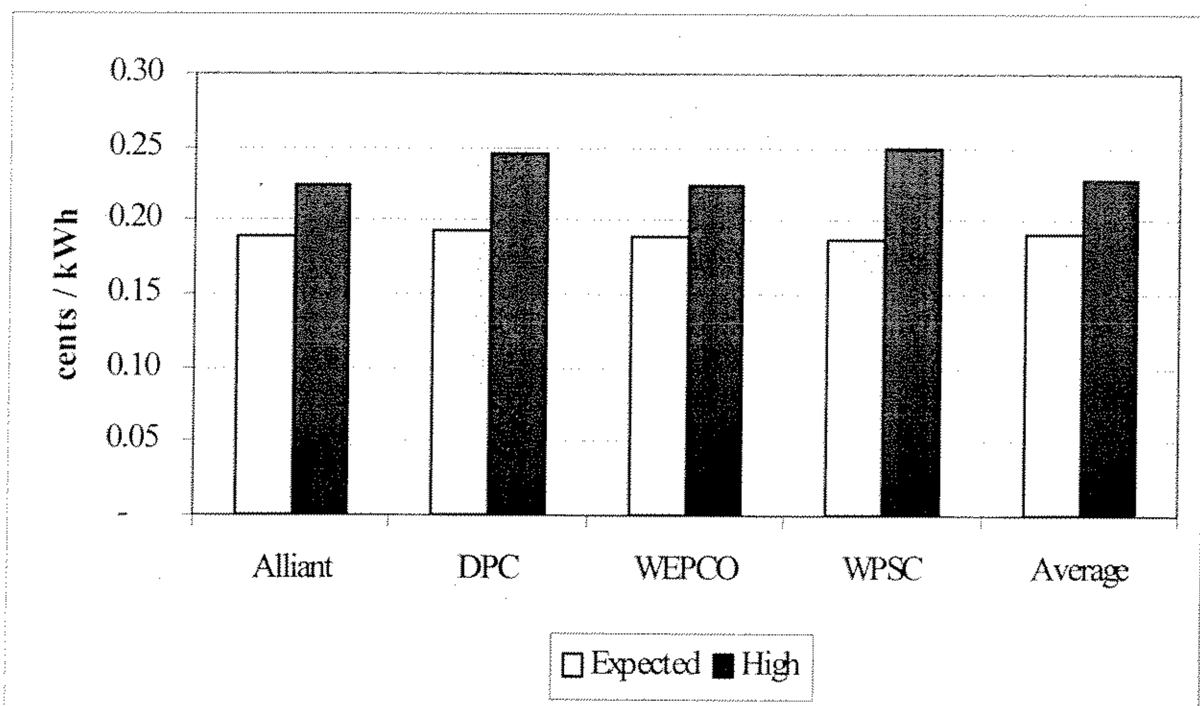
At the final control level of 88%, as illustrated in *Figure 3 - Incremental Electricity Cost at the 88% Average Mercury Control Level for Surrogate Control Technology*, the incremental cost is almost comparable among all major utilities. The cost for the expected case for all major utilities is 0.19 cents/kWh. The cost for the high case for all major utilities is 0.22 to 0.25 cents/kWh.

Figure 2. Incremental Electricity Cost at the 47% Average Mercury Control Level for Surrogate Control Technology.



R = the utility mercury removal or control level.

Figure 3. Incremental Electricity Cost at the 88% Average Mercury Control Level for Surrogate Control Technology.



Estimated Consumer Costs

The cost impact to the consumer or ratepayer is estimated by applying the incremental electricity cost to indices of electricity consumption. The estimated cost impacts to the residential, commercial, and industrial consumer are compiled in *Table 13 - Estimate of Consumer Incremental Cost from Surrogate Control Technology (dollars / year).*

The cost to the residential consumer is based on the average household consuming 770 kWh per month or 9,240 kWh per year **(8)**. The calculated initial residential household cost beginning in 2010 as shown in *Figure 4 - Estimate of Annual Household Cost vs. Mercury Control for Surrogate Control Technology*, may range from 6 to 7 dollars per year. The final cost in 2015 is estimated to range from 18 to 21 dollars per year. The annual household cost versus mercury control achieved through the installation schedule is illustrated in *Figure 4*.

Table 13. Estimate of Consumer Incremental Cost from Surrogate Control Technology (dollars / year)

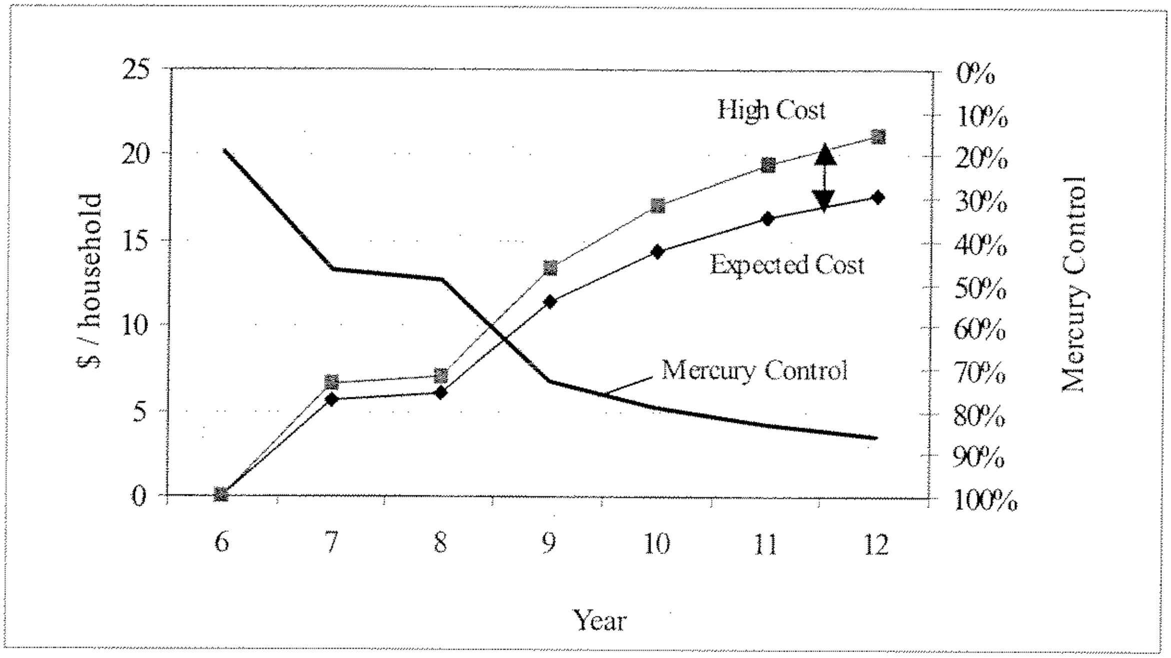
Sector	Unit	Indices	Initial Cost ($/year)		Final Cost ($/year)	
			Expected	High	Expected	High
Residential	Household	9,240 kWh/year (1)	6	7	18	21
Commercial	Customer	60,513 kWh/year (1)	37	44	116	138
Industrial	Net Proceeds	0.46 kWh/$1000 (2)	0.28	0.33	0.88	1.05
	Value Shipped Product	0.21 kWh/$1000 (3)	0.13	0.16	0.41	0.49

1) Wisconsin Energy Statistics 2002, Wisconsin Energy Bureau
2) Indices calculated as the total industrial electric consumption of 23,523 per Wisconsin Energy Statistics 2002, divided by the total manufacturing value added of 50,998,900,000 dollars in 1996 per Wisconsin Economic Profile, Department of commerce.
3) Indices calculated as the total industrial electric consumption of 23,523 per Wisconsin Energy Statistics 2002, divided by the total manufacturing value added of 109,593,100,000 dollars in 1996 per Wisconsin Economic Profile, Department of commerce.

According to the Wisconsin Energy Bureau the average commercial customer purchases 60,513 kWh per year **(8)**. On this basis the initial cost in 2010 may range from 37 to 44 dollars per year. At the final control level in 2015 the cost is 116 to 138 dollars per year.

In the industrial sector electric consumption varies considerably between customers making it difficult to determine a meaningful average cost. However, one means of expressing the added cost is in relation to the value of net proceeds and of shipped product. Indices were developed based on the total industrial electricity consumption of 23,523 megawatt-hours for 2002 **(9)** and dividing this by either the net proceeds of 50,998,900,000 dollars or value shipped of 109,593,100,000 dollars determined in for the 1996 business year. **(9)**. This results in the indices of 0.46 kWh electricity consumed per $1000 of net proceeds and 0.21 kWh of electricity consumed per $1000 of the value of shipped products. The cost is then determined by multiplying these indices by the calculated incremental electricity cost due to mercury control.

Figure 4. Estimate of Annual Household Cost vs. Mercury Control Achieved by the Surrogate Control Technology



The Industrial estimated cost impact using the net proceeds basis is 0.28 to 0.33 dollars per $1000 at the initial reduction in 2010 and 0.88 to 1.05 dollars per $1000 at the final reduction level in 2015. At the final reduction level this represents a 0.088% to 0.11% decrease in the net proceeds. Similarly on the basis of the value of shipped product, the cost per $1000 is 0.13 to 0.16 dollars in 2010 and 0.41 to 0.49 dollars in 2015.

This results in an electricity cost of 0.18 to 0.23 dollars per $1000 of added value for the initial reduction and 0.65 to 0.78 dollars per $1000 of added value at the final reduction level. At the final reduction level this represents a 0.65 to 0.078% increase to manufacturing cost. The cost is lower if based on the value of shipped product.

References

1. (Kilgroe, et al, Dec 2001), "Control of Mercury Emissions from Coal-Fired Electric Utility Boilers: Interim Report", USEPA, Office of Research and Development, EPA-600/R-01-109.

2. (EPRI, September 2000), "An Assessment of Mercury Emissions from Coal-Fired Power Plants", EPRI, Palo Alto, Ca, TR-1000608, September 2000.

3. (USEPA, 2003), " Clean Air Markets – Progress and Results", Acid Rain Program, http://www.epa.gov/airmarkets/emissions/prelimarp/index.html, 2003.

4. (WDNR, 2003), "Air Emissions Inventory", Wisconsin Department of Natural Resources internal database, reports for 1997 through 2001.

5. (EPRI, 2001), "Mercury Removal Options for Power Plants – A Synopsis of EPRI Reports for Public Release", EPRI, Palo Alto, Ca, March 2001.

6. (WPSC, 2000), "Investigation on the Commission's Own Motion Into Issues Associated With Compliance by Wisconsin Electric Utilities With the U.S. Environmental Protection Agency's New Nitrogen Oxide Emissions Requirements – Final Decision", Wisconsin Public Service Commission, Madison, Wisconsin, Docket 05-CE-108.

7. (Ramme, 2002), "Expected Impacts to Coal Combustion Product Utilization (Risks, Landfilling, and Costs) from Mercury Sorbent Materials", Power point presentation, Wisconsin Electric, Milwaukee, Wisconsin.

8. (WEB, 2002), "Wisconsin Energy Statistics", Wisconsin Energy Bureau, Department of Administration, Madison, Wisconsin, 2002.

9. (WDOC, 2002), "Wisconsin Economic Profile", Wisconsin Department of Commerce, Madison, Wisconsin, 2002.

Appendix

List of Tables

Table A1. Major Utility Units Firing Coal in 1997 – 2001, Fuel Consumption, Utilization, and Electric Generation

Company	Source	Unit	Year Installed	Unit Age	Capacity (MW)	Average Fuel Consumption (mmBTU) 1997-1999	1998-2000	1999-2001	Average Capacity Factor (%) 1997-1999	1998-2000	1999-2001	Average Electric Generation (kWh) 1997-1999	1998-2000	1999-2001
	Columbia	1	1975	28	512	41,042,808	41,371,588	41,466,684	80%	80%	80%	3,570,759,167	3,599,363,335	3,607,636,768
	Columbia	2	1978	25	511	43,087,156	42,183,095	41,374,071	84%	82%	80%	3,741,297,658	3,662,797,204	3,592,548,930
	Edgewater	3	1951	52	60	4,276,938	4,572,581	4,649,996	58%	62%	63%	304,047,725	325,065,024	330,568,460
	Edgewater	4	1969	34	330	19,405,030	19,375,602	19,328,937	63%	63%	63%	1,814,581,975	1,811,830,198	1,807,466,481
Alliant	Edgewater	5	1985	18	380	29,902,952	30,190,928	29,465,949	78%	79%	77%	2,602,638,945	2,627,703,278	2,564,603,927
	Nelson Dewey	1	1959	44	100	7,134,536	6,705,282	6,807,787	65%	61%	62%	566,233,042	532,165,212	540,300,582
	Nelson Dewey	2	1962	41	100	7,589,344	7,173,473	6,625,805	69%	65%	60%	602,328,889	569,323,228	525,857,513
	Rock River	1	1954	49	75	3,523,611	2,272,353	1,065,675	41%	27%	13%	272,444,124	175,697,371	82,397,526
	Rock River	2	1955	48	75	3,925,967	2,566,126	1,372,239	46%	30%	16%	303,554,149	198,411,830	106,100,954
	Alma	1	1959	44	20	522,117	603,429	575,214	30%	35%	33%	52,739,125	60,952,391	58,102,424
	Alma	2	1959	44	22	447,864	513,254	515,129	26%	30%	30%	49,762,630	57,028,185	57,236,519
	Alma	3	1959	44	21	478,393	547,839	635,054	19%	22%	25%	34,596,563	39,618,782	45,926,026
DPC	Alma	4	1959	44	59	2,751,718	2,883,236	2,359,946	59%	62%	51%	304,942,453	319,517,137	261,526,661
	Alma	5	1959	44	85	3,737,677	3,903,264	3,559,973	54%	57%	52%	402,869,101	420,717,017	383,715,071
	Genoa	3	1969	34	376	20,097,173	18,827,523	19,561,645	75%	71%	73%	2,486,111,835	2,329,050,427	2,419,864,581
	JP Madget	JPM	1979	24	374	24,158,710	25,181,642	25,457,875	73%	76%	77%	2,387,779,477	2,488,883,254	2,516,185,353
	Oak Creek	5	1960	43	258	13,536,526	12,823,958	14,930,492	67%	64%	74%	1,519,766,627	1,439,765,557	1,676,269,374
	Oak Creek	6	1961	42	260	12,912,302	15,060,968	13,733,384	65%	75%	69%	1,470,520,634	1,715,221,974	1,564,029,753
	Oak Creek	7	1965	38	280	20,788,775	21,072,776	19,658,702	91%	92%	86%	2,231,923,661	2,262,414,565	2,110,596,876
	Oak Creek	8	1967	36	305	19,028,892	19,774,981	20,884,450	85%	88%	93%	2,260,931,850	2,349,579,005	2,481,401,384
	Pleasant Prairie	1	1980	23	580	51,581,077	48,520,824	50,035,533	96%	90%	93%	4,858,237,197	4,570,002,941	4,712,667,966
	Pleasant Prairie	2	1985	18	580	50,871,606	51,730,991	50,388,042	94%	96%	93%	4,791,414,692	4,872,357,061	4,745,869,528
	Port Washington	1	1935	68	80	3,379,433	3,675,803	3,710,639	35%	38%	38%	244,222,824	265,640,687	268,158,217
WE	Port Washington	2	1943	60	80	3,989,526	4,087,488	3,757,328	41%	42%	39%	288,312,605	295,392,111	271,532,261
	Port Washington	3	1948	55	82	4,080,525	3,990,400	3,920,299	42%	41%	40%	302,261,111	295,585,160	290,392,519
	Port Washington	4	1949	54	80	3,363,659	3,780,261	3,749,563	35%	39%	39%	243,082,855	273,189,618	270,971,153
	Valley	1	1968	35	64	4,166,888	4,022,680	4,028,322	56%	54%	54%	315,225,545	304,316,217	304,743,061
	Valley	1	1968	35	62	4,228,982	3,977,843	4,037,098	57%	54%	54%	309,925,419	291,520,433	295,862,998
	Valley	2	1969	34	70	4,501,956	4,439,179	4,401,651	61%	60%	60%	375,163,028	369,931,556	366,804,278
	Valley	2	1969	34	70	4,684,626	4,647,078	4,452,039	64%	63%	61%	390,385,500	387,256,500	371,003,250
	County Plant	1,2,3		> 40		1,404,661	1,404,661	1,404,661	38%	38%	38%	ND	ND	ND
	Pulliam	3	1943	60	26	1,058,716	1,125,279	1,123,708	34%	37%	36%	78,289,579	83,211,782	83,095,586
	Pulliam	4	1947	56	27	1,358,317	1,564,953	1,628,013	44%	51%	53%	104,307,619	120,175,546	125,018,038
	Pulliam	5	1949	54	52	3,681,988	3,838,910	3,924,780	74%	77%	79%	336,491,025	350,831,845	358,679,337
	Pulliam	6	1951	52	67	5,454,586	5,576,382	5,909,046	83%	85%	90%	489,954,799	500,895,018	530,776,383
WPSC	Pulliam	7	1958	45	88	6,545,703	7,018,831	6,398,109	93%	100%	91%	718,321,353	770,242,122	702,124,408
	Pulliam	8	1964	39	135	10,486,074	10,285,958	10,069,780	93%	91%	89%	1,099,083,808	1,078,108,987	1,055,450,509
	Weston	1	1954	49	68	4,179,546	4,157,853	4,473,425	58%	58%	62%	344,495,885	342,707,856	368,718,667
	Weston	2	1960	43	92	6,139,392	6,698,297	6,809,183	81%	89%	90%	656,772,132	716,561,969	728,424,264
	Weston	3	1981	22	337	29,642,435	29,378,815	28,993,558	87%	86%	85%	2,574,613,526	2,551,716,635	2,518,254,938
Alliant					2,143	159,888,341	156,411,028	152,157,144	70%	69%	67%	13,777,885,674	13,502,356,680	13,157,481,140
DPC					957	52,193,652	52,460,187	52,664,835	67%	68%	68%	5,718,801,184	5,715,767,194	5,742,556,635
WE					2,851	201,114,774	201,605,231	201,687,545	77%	77%	77%	19,601,373,547	19,692,173,386	19,730,302,619
WPSC					892	68,546,757	69,645,278	69,329,602	81%	82%	82%	6,402,329,728	6,514,451,760	6,470,542,128
Total					6,843	481,743,523	480,121,724	475,839,126	74%	74%	73%	45,500,390,132	45,424,749,020	45,100,882,521

Notes:

- Fuel consumption for units > 25 MW derived from USEPA Acid Rain database.
- Fuel consumption for units < 25 MW derived from DNR air emission inventory.
- Capacity Factor = fuel consumption / theoretical fuel consumption x 100
- Electric generation = Unit Capacity x Capacity Factor x 8760 hours per year

Table A2. Esumated Mercury Control and Average Emissions for 1997 through 2001

Major Utility	Facility	Gen Unit	Fuel Class	Fuel Hg Content (lb/Tbtu)	Chlorine (ppm)	Existing Air Pollution Control Equipment	Estimate Mercury Control from Existing Equipment (1)	Other Indications of Control Efficiency (see Key)	Annual Fuel Mercury Content (lbs)			Annual Mercury Emissions (lbs)		
									3 Year Ave 1997 - 1999	3 Year Ave 1998 - 2000	3 Year Ave 1999 - 2001	3 Year Ave 1997 - 1999	3 Year Ave 1998 - 2000	3 Year Ave 1999 - 2001
Alliant	Columbia	1**	Sub	4.77	50	ESPh	0%	negative/10%	196	197	198	196	197	198
	Columbia	2	Sub	4.77	50	ESPc	12%		206	201	197	180	176	173
	Edgewater	3	Sub	4.37	61	ESPc	14%		19	20	20	16	17	17
	Edgewater	4	Sub	4.37	61	ESPc	14%		85	85	84	73	72	72
	Edgewater	5	Sub	4.37	61	ESPc	14%		131	132	129	112	113	110
	Nelson Dewey	1**	Sub	6.25	409	ESPh	15%	53%/negative	45	42	43	38	36	36
	Nelson Dewey	2	Sub	6.25	409	ESPh	15%	53%/negative	47	45	41	40	38	35
	Rock River	1	Sub	6.19	344	ESPc	30%		22	14	7	15	10	5
	Rock River	2	Sub	6.19	344	ESPc	30%		24	16	8	17	11	6
DPC	Alma	1*	Bitum	5.69		ESPc	35%		3	3	3	2	2	2
	Alma	2*	Bitum	5.69		ESPc	35%		3	3	3	2	2	2
	Alma	3*	Bitum	5.69		ESPc	35%		3	3	4	2	2	2
	Alma	4	Sub/Bitum	4.19	1529	ESPc	30%		12	12	10	10	11	9
	Alma	5	Sub/Bitum	4.19	1529	ESPc	30%		16	16	15	14	15	13
	Genoa	3	Sub/Bitum	4.6	2552	ESPc	55%		92	87	90	42	39	40
	JP Madget	1	Sub	4.84	19	ESPh	0%		117	122	123	117	122	123
WE	Oak Creek	5	Sub/Bitum	5.34	346	ESPc	30%		72	68	80	50	48	56
	Oak Creek	6	Sub/Bitum	5.26	246	ESPc	28%		68	79	72	49	57	52
	Oak Creek	7	Sub/Bitum	5.32	313	ESPc	30%		111	112	105	78	79	73
	Oak Creek	8	Sub/Bitum	5.12	80	ESPc	21%		97	101	107	77	80	85
	Pleasant Prairie	1	Sub	9.41	14	ESPc	0%	5%	485	457	471	485	457	471
	Pleasant Prairie	2	Sub	9.41	14	ESPc	0%	5%	479	487	474	479	487	474
	Port Washington	1	Bitum	6.83	246	ESPc	20%		23	25	25	18	20	20
	Port Washington	2	Bitum	6.83	1231	ESPc	40%		27	28	26	16	17	15
	Port Washington	3	Bitum	6.83	1231	ESPc	40%		28	27	27	17	16	16
	Port Washington	4**	Bitum	6.83	246	ESPc	20%	29%/44%	23	26	26	18	21	20
	Valley	1	Bitum	3.51	548	FF	72%	negative	15	14	14	4	4	4
	Valley	1	Bitum	3.51	548	FF	72%	negative	15	14	14	4	4	4
	Valley	2**	Bitum	3.51	548	FF	72%	negative	16	16	15	4	4	4
	Valley	2	Bitum	3.51	548	FF	72%	negative	16	16	16	5	5	4
	County Pant	1,2,3*	Bitum	7.8		ESPc	36%		11	11	11	7	7	7

Table A2. Estimated Mercury Control and Average Emissions for 1997 through 2001 (con't)

Major Utility	Facility	Gen Unit	Fuel Class	Fuel Hg Content (lb/Tbtu)	Chlorine (ppm)	Existing Air Pollution Control Equipment	Estimate Mercury Control from Existing Equipment (1)	Other Indications of Control Efficiency (see Key)	Annual Fuel Mercury Content (lbs) 3 Year Ave 1997 - 1999	Annual Fuel Mercury Content (lbs) 3 Year Ave 1998 - 2000	Annual Fuel Mercury Content (lbs) 3 Year Ave 1999 - 2001	Annual Mercury Emissions (lbs) 3 Year Ave 1997 - 1999	Annual Mercury Emissions (lbs) 3 Year Ave 1998 - 2000	Annual Mercury Emissions (lbs) 3 Year Ave 1999 - 2001
WPSC	Pulliam	3	Sub	3.1	64	ESPc	22%		3	3	3	3	3	3
	Pulliam	4	Sub	3.1	64	ESPc	22%		4	5	5	3	4	4
	Pulliam	5	Sub	3.1	64	ESPc	22%		11	12	12	9	9	9
	Pulliam	6	Sub	3.1	64	ESPc	22%		17	17	18	13	13	14
	Pulliam	7	Sub	3.1	64	ESPc	22%		20	22	20	16	17	15
	Pulliam	8	Sub	3.1	64	ESPc	22%		33	32	31	25	25	24
	Weston	1	Sub	4.75	158	ESPc	28%		20	20	21	14	14	15
	Weston	2	Sub	4.75	158	ESPc	28%		29	32	32	21	23	23
	Weston	3	Sub	4.75	158	ESPh	7%		141	140	138	131	130	128
							Subtotals	Alliant	774	752	728	687	671	653
								DPC	245	246	248	188	192	192
								WE	1,486	1,481	1,482	1,312	1,304	1,306
								WPSC	278	282	281	235	237	236
								Total	2,783	2,762	2,739	2,422	2,405	2,387

System-Wide Percent Mercury Control			
Major Utility	3 Year Ave 1997 - 1999	3 Year Ave 1998 - 2000	3 Year Ave 1999 - 2001
Alliant	11%	11%	10%
DPC	23%	22%	22%
WE	12%	12%	12%
WPSC	16%	16%	16%
Major Utility Average	13%	13%	13%

Notes

1) The Electric Power Research Institute (EPRI) evaluated the ICR data and estimated unit emissions based on fuel chlorine content and pollution control equipment. This estimate either agreed with or is more conservative for units that participated in ICR Phase II testing.

* - Units that were not required to perform ICR Phase I fuel testing. Fuel Hg content estimated using ICR database by fuel type and origin.

** - Units were required to perform ICR Phase II flue gas mercury emission and speciation testing.

Key: "Other Indications of Hg Control Efficiency"

Columbia 1 - ICR phase II testing indicated 10% reduction measured on a flue gas to flue gas basis across the control equipment and negative reduction measured on a coal to post control equipment flue gas. (EPA-600/R-01-109, De

Nelson Dewey - ICR phase II testing indicated a negative reduction measured on a flue gas to flue gas basis across the control equipment and 53% reduction measured on a coal to post control equipment flue gas. (EPA-600/R-01-10

Pleasant Prairie 2 - Flue gas testing across pollution control equipment conducted during the full scale testing of AC sorbent injection indicated a baseline reduction of 5%.

Port Washington 4 - ICR phase II testing indicated 29% reduction measured on a flue gas to flue gas basis across the control equipment and 44% removal measured on a coal to post control equipment flue gas. (EPA-600/R-01-109, I

Valley 3 - ICR phase II testing yielded negative results that EPA indicated as invalid. (EPA-600/R-01-109, Dec 2001)

Table A3. Estimated Mercury Control and Emissions based on Anticipated Equipment and Operations in 2008.

Major Utility	Facility	Unit	Fuel Class	Fuel Hg Content (lb/Tbtu)	Chlorine (ppm)	Existing Air Pollution Control Equipment	Hg Control Efficency (1)	Future Anticipated Change in Operation / Configuration	Annual Fuel Mercury Content (lbs) using baseline fuel	Annual Mercury Emissions (lbs) using baseline fuel consumption
Alliant	Columbia	1**	Sub	4.77	50	ESPh	0%		196	196
	Columbia	2	Sub	4.77	50	ESPc	12%		206	180
	Edgewater	3	Sub	4.37	61	ESPc	14%		19	16
	Edgewater	4	Sub	4.37	61	ESPc	14%		85	73
	Edgewater	5	Sub	4.37	61	ESPc	14%		131	112
	Nelson Dewey	1**	Sub	6.25	409	ESPh	15%		45	38
	Nelson Dewey	2	Sub	6.25	409	ESPh	15%		47	40
	Rock River	1	Sub	6.19	344	ESPc	100%	Conversion to NG	22	-
	Rock River	2	Sub	6.19	344	ESPc	100%	Conversion to NG	24	-
DPC	Alma	1*	Bitum	5.69		ESPc	35%		3	2
	Alma	2*	Bitum	5.69		ESPc	35%		3	2
	Alma	3*	Bitum	5.69		ESPc	35%		4	2
	Alma	4	Sub/Bitum	4.19	1529	ESPc	30%		10	9
	Alma	5	Sub/Bitum	4.19	1529	ESPc	30%		15	13
	Genoa	3	Sub/Bitum	4.6	2552	ESPc	55%		90	40
	JP Madget	1	Sub	4.84	19	ESPh	0%		123	123
WE	Oak Creek	5	Sub/Bitum	5.34	346	ESPc	30%		80	56
	Oak Creek	6	Sub/Bitum	5.26	246	ESPc	28%		72	52
	Oak Creek	7	Sub/Bitum	5.32	313	ESPc	30%		105	73
	Oak Creek	8	Sub/Bitum	5.12	80	ESPc	21%		107	85
	Pleasant Prairie	1	Sub	9.41	14	ESPc	0%		471	471
	Pleasant Prairie	2	Sub	9.41	14	ESPc	0%		474	474
	Port Washington	1	Bitum	6.83	246	ESPc	100%	Repowered to NG	25	-
	Port Washington	2	Bitum	6.83	1231	ESPc	100%	Repowered to NG	26	-
	Port Washington	3	Bitum	6.83	1231	ESPc	100%	Repowered to NG	27	-
	Port Washington	4**	Bitum	6.83	246	ESPc	100%	Repowered to NG	26	-
	Valley	1	Bitum	3.51	548	FF	72%		14	4
	Valley	1	Bitum	3.51	548	FF	72%		14	4
	Valley	2**	Bitum	3.51	548	FF	72%		15	4
	Valley	2	Bitum	3.51	548	FF	72%		16	4
	County Plant	1,2,3*	Bitum	7.8		ESPc	36%		11	7

Table A3. Estimated Mercury Control and Emissions based on Anticipated Equipment and Operations in 2008 (con't).

Major Utility	Facility	Unit	Fuel Class	Fuel Hg Content (lb/Tbtu)	Chlorine (ppm)	Existing Air Pollution Control Equipment	Hg Control Efficency (1)	Future Anticipated Change in Operation / Configuration	Annual Fuel Mercury Content (lbs) using baseline fuel	Annual Mercury Emissions (lbs) using baseline fuel consumption
WPSC	Pulliam	3	Sub	3.1	64	ESPc	22%		3	3
	Pulliam	4	Sub	3.1	64	ESPc	22%		5	4
	Pulliam	5	Sub	3.1	64	ESPc	22%		12	9
	Pulliam	6	Sub	3.1	64	ESPc	22%		18	14
	Pulliam	7	Sub	3.1	64	ESPc	22%		20	15
	Pulliam	8	Sub	3.1	64	ESPc	22%		31	24
	Weston	1	Sub	4.75	158	ESPc	28%		21	15
	Weston	2	Sub	4.75	158	ESPc	28%		32	23
	Weston	3	Sub	4.75	158	FF	49%	Fabric Filter PM Cntrl	138	70
							Subtotals	Alliant	774	654
								DPC	248	192
								WE	1,482	1,234
								WPSC	281	178
								Major Utility Total	2,785	2,259

System-Wide Mercury Control	
Alliant	15%
DPC	22%
WE	17%
WPSC	37%
Major Utility Average	19%

Notes

1) Control efficiency based on determination in Table A2 for units without equipment changes. For units with changes the ICR data results is applied for that unit type and fuel.

* - Units that were not required to perform ICR Phase I fuel testing. Fuel Hg content estimated using ICR database by fuel type and origin.

** - Units were required to perform ICR Phase II flue gas mercury emission and speciation testing.

Table A4. Estimated Percent Mercury Control for each Utility Resulting from Existing and Surrogate Control Technology

Utility	Source	Unit	CAP MW	Age	Existing Mercury Control by 2008	Surrogate Control Technology		Surrogate Control Technology and Total Mercury Control as Percent of Utility Total Mercury									
						System Configuration	Unit Control Efficiency	3	4	5	6	7	8	9	10	11	12
Alliant (1)	Edgewater	3	60	51	0.4%	AC inj	60%								1.3%	1.3%	1.3%
	Rock River	1	75	48	2.8%												
	Rock River	2	75	47	3.1%												
	Nelson Dewey	1	100	43	0.9%	AC inj	60%							3.5%	3.5%	3.5%	3.5%
	Nelson Dewey	2	100	40	0.9%	AC inj	60%						3.7%	3.7%	3.7%	3.7%	3.7%
	Edgewater	4	330	33	1.6%	ACinj / FF	90%									9.9%	9.9%
	Edgewater	5	380	17	2.4%	ACinj / FF	90%								15.2%	15.2%	15.2%
	Columbia	2	511	27	3.3%	ACinj / FF	90%							23.9%	23.9%	23.9%	23.9%
	Columbia	1	512	24	0.0%	ACinj / FF	90%					22.8%	22.8%	22.8%	22.8%	22.8%	22.8%
	Surrogate Technology Controlled Emission							0%	0%	0%	0%	23%	27%	54%	70%	80%	80%
	Existing Equipment Controlled Emissions				15.4%			15%	15%	15%	15%	15%	15%	10%	8%	6%	6%
	Total Controlled Emissions							15%	15%	15%	15%	38%	41%	64%	78%	86%	86%
DPC	Alma	1	20	43	0.5%	AC inj	60%								0.7%	0.7%	0.7%
	Alma	3	21	43	0.5%	AC inj	60%								0.7%	0.7%	0.7%
	Alma	2	22	43	0.4%	AC inj	60%								0.6%	0.6%	0.6%
	Alma	4	59	43	0.4%	AC inj	60%							2.8%	2.8%	2.8%	2.8%
	Alma	5	85	43	0.7%	AC inj	60%						3.8%	3.8%	3.8%	3.8%	3.8%
	JP Madget	1	374	23	0.0%	ACinj / FF	90%					43.0%	43.0%	43.0%	43.0%	43.0%	43.0%
	Genoa	3	376	33	20.0%	ACinj / FF	90%							34.0%	34.0%	34.0%	34.0%
	Surrogate Technology Controlled Emission							0%	0%	0%	0%	43%	47%	84%	86%	86%	86%
	Existing Equipment Controlled Emissions				22.5%			23%	23%	23%	23%	23%	22%	1%	0%	0%	0%
	Total Controlled Emissions							23%	23%	23%	23%	66%	69%	85%	86%	86%	86%
WE (2)	County Plant	1,2,3			0.3%	AC inj	60%								0.5%	0.5%	0.5%
	Valley	1	62	34	0.7%	AC inj	80%							0.8%	0.8%	0.8%	0.8%
	Valley	1	64	34	0.7%	AC inj	80%							0.8%	0.8%	0.8%	0.8%
	Valley	2	70	33	0.8%	AC inj	80%						0.9%	0.9%	0.9%	0.9%	0.9%
	Valley	2	70	33	0.8%	AC inj	80%						0.9%	0.9%	0.9%	0.9%	0.9%
	Port Washington	1	80	67	1.7%												
	Port Washington	2	80	59	1.7%												
	Port Washington	3	82	54	1.8%												
	Port Washington	4	80	53	1.7%												
	Oak Creek	5	258	42	1.6%	ACinj / FF	90%								4.4%	4.4%	4.4%
	Oak Creek	6	260	41	1.4%	ACinj / FF	90%								4.1%	4.1%	4.1%
	Oak Creek	7	280	37	2.1%	ACinj / FF	90%									6.7%	6.7%
	Oak Creek	8	305	35	1.5%	ACinj / FF	90%										5.9%
	Pleasant Prairie	1	580	22	0.0%	ACinj / FF	90%					29.6%	29.6%	29.6%	29.6%	29.6%	29.6%
	Pleasant Prairie	2	580	17	0.0%	ACinj / FF	90%							29.2%	29.2%	29.2%	29.2%
	Surrogate Technology Controlled Emission							0%	0%	0%	0%	30%	31%	62%	71%	77%	84%
	Existing Equipment Controlled Emissions				16.8%			17%	17%	17%	17%	17%	15%	14%	11%	9%	7%
	Total Controlled Emissions							17%	17%	17%	17%	46%	47%	76%	82%	86%	91%

Table A4. Estimated Percent Mercury Control for each Utility Resulting from Existing and Surrogate Control Technology (con't).

Utility	Source	Unit	CAP MW	Age	Existing Mercury Control by 2008	Surrogate Control Technology: System Configuration	Surrogate Control Technology: Unit Control Efficiency	Surrogate Control Technology and Total Mercury Control as Percent of Utility Total Mercury: 3	4	5	6	7	8	9	10	11	12
WPSC(3)	Pulliam	3	26	59	0.3%	AC inj	60%							0.7%	0.7%	0.7%	0.7%
	Pulliam	4	27	55	0.3%	AC inj	60%							0.9%	0.9%	0.9%	0.9%
	Pulliam	5	52	53	1.0%	AC inj	60%						2.5%	2.5%	2.5%	2.5%	2.5%
	Pulliam	6	67	51	1.5%	AC inj	60%						3.6%	3.6%	3.6%	3.6%	3.6%
	Weston	1	68	48	2.1%	ACinj / FF	90%									6.4%	6.4%
	Pulliam	7	88	44	1.6%	ACinj / FF	90%										6.6%
	Weston	2	92	42	3.2%	ACinj / FF	90%								9.4%	9.4%	9.4%
	Pulliam	8	135	38	2.5%	ACinj / FF	90%							10.5%	10.5%	10.5%	10.5%
	Weston	3	337	21	24.0%	ACinj / FF	90%					45.5%	45.5%	45.5%	45.5%	45.5%	45.5%
	Surrogate Technology Controlled Emission							0%	0%	0%	0%	46%	52%	64%	73%	80%	86%
	Existing Equipment Controlled Emissions				36.5%			37%	37%	37%	37%	13%	10%	7%	4%	2%	0%
	Total Controlled Emissions							37%	37%	37%	37%	58%	62%	71%	77%	81%	86%
Major Utility Average	Surrogate Technology Controlled Emission							0%	0%	0%	0%	30%	34%	62%	73%	81%	84%
	Existing Equipment Controlled Emissions				19%			19%	19%	19%	19%	17%	14%	11%	8%	6%	4%
	Total Controlled Emissions							19%	19%	19%	19%	47%	48%	73%	81%	87%	88%

Notes:

Surrogate Control Technology:

AC: non-Core Generation Units - Injection of activated carbon prior to existing particulate control equipment with a unit control efficiency of 60% for units with an electrostatic precipitator and 80% for units with a fabric filter particulate

AC / FF: Core Generation Units - Installation of a dedicate fabric filter along with activated carbon injection after the existing particulate control equipment to yield a 90% unit control efficiency.

"Existing Controlled Emissions" - Reflects the amount of a utility's percent mercury control occuring at each unit. The unit's control efficiency is based on EPRI calculations or updated estimates based on ICR correlations and 1998-2000 fuel cons

1) Rock River existing controlled emissions reflects conversion from coal to natural gas.

2) Port Washington control based on planned repowering.

3) Weston 1, Weston 2, 3, Pulliam 7, and Pulliam 8 surrogate technology is polishing Fabric Filter / AC injection.

Table A5. Mercury Control Cost for Application of Surrogate Control Technology.

Company	Source	Unit	Capacity MW	Age	Estimated Cost in Nth Year ($M)						High Cost in Nth Year ($M)					
					7	8	9	10	11	12	7	8	9	10	11	12
Alliant	Edgewater	3	60	51				0.2	0.2	0.2				0.2	0.2	0.2
	Rock River	1	75	48												
	Rock River	2	75	47												
	Nelson Dewey	1	100	43			0.5	0.5	0.5	0.5			0.5	0.5	0.5	0.5
	Nelson Dewey	2	100	40		0.5	0.5	0.5	0.5	0.5		0.5	0.5	0.5	0.5	0.5
	Edgewater	4	330	33					4.4	4.4					5.0	5.0
	Edgewater	5	380	17				5.6	5.6	5.6				6.7	6.7	6.7
	Columbia	2	511	27			7.7	7.7	7.7	7.7			9.0	9.0	9.0	9.0
	Columbia	1	512	24	7.7	7.7	7.7	7.7	7.7	7.7	9.0	9.0	9.0	9.0	9.0	9.0
	Total Annual Control Cost				8	8	16	22	26	26	9	10	19	26	31	31
	Accumulated Total Cost through Nth Year				8	16	32	54	81	107	9	19	37	63	94	125
DPC	Alma	1	20	43				0.0	0.0	0.0				0.1	0.1	0.1
	Alma	3	21	43				0.0	0.0	0.0				0.1	0.1	0.1
	Alma	2	22	43				0.0	0.0	0.0				0.1	0.1	0.1
	Alma	4	59	43			0.2	0.2	0.2	0.2			0.3	0.3	0.3	0.3
	Alma	5	85	43		0.3	0.3	0.3	0.3	0.3		0.4	0.4	0.4	0.4	0.4
	JP Madget	1	374	23	5.4	5.4	5.4	5.4	5.4	5.4	6.3	6.3	6.3	6.3	6.3	6.3
	Genoa	3	376	33			5.4	5.4	5.4	5.4			6.5	6.5	6.5	6.5
	Total Annual Control Cost				5	6	11	11	11	11	6	7	14	14	14	14
	Accumulated Total Cost through Nth Year				5	11	22	34	45	57	6	13	27	40	54	68
WE	County Plant	1,2,3						0.3	0.3	0.3				0.3	0.3	0.3
	Valley	1	62	34			0.4	0.4	0.4	0.4			0.4	0.4	0.4	0.4
	Valley	1	64	34			0.4	0.4	0.4	0.4			0.4	0.4	0.4	0.4
	Valley	2	70	33		0.4	0.4	0.4	0.4	0.4		0.4	0.4	0.4	0.4	0.4
	Valley	2	70	33		0.4	0.4	0.4	0.4	0.4		0.4	0.4	0.4	0.4	0.4
	Port Washington	1	80	67												
	Port Washington	2	80	59												
	Port Washington	3	82	54												
	Port Washington	4	80	53												
	Oak Creek	5	258	42				3.7	3.7	3.7				4.5	4.5	4.5
	Oak Creek	6	260	41				3.6	3.6	3.6				4.4	4.4	4.4
	Oak Creek	7	280	37					4.4	4.4					5.3	5.3
	Oak Creek	8	305	35						4.8						5.7
	Pleasant Prairie	1	580	22	9.7	9.7	9.7	9.7	9.7	9.7	11.1	11.1	11.1	11.1	11.1	11.1
	Pleasant Prairie	2	580	17			9.7	9.7	9.7	9.7			11.1	11.1	11.1	11.1
	Total Annual Control Cost				10	10	21	28	33	37	11	12	24	33	38	44
	Accumulated Total Cost through Nth Year				10	20	41	69	102	139	11	23	47	80	118	161

Table A5. Mercury Control Cost for Application of Surrogate Control Technology (con't).

Company	Source	Unit	Capacity MW	Age	Estimated Cost in Nth Year ($M)						High Cost in Nth Year ($M)					
					7	8	9	10	11	12	7	8	9	10	11	12
WPSC	Pulliam	3	26	59			0.1	0.1	0.1	0.1			0.1	0.1	0.1	0.1
	Pulliam	4	27	55			0.1	0.1	0.1	0.1			0.1	0.1	0.1	0.1
	Pulliam	5	52	53		0.2	0.2	0.2	0.2	0.2		0.3	0.3	0.3	0.3	0.3
	Pulliam	6	67	51		0.3	0.3	0.3	0.3	0.3		0.4	0.4	0.4	0.4	0.4
	Weston	1	68	48					0.9	0.9					1.5	1.5
	Pulliam	7	88	44						1.4						2.0
	Weston	2	92	42				1.4	1.4	1.4				2.0	2.0	2.0
	Pulliam	8	135	38			2.1	2.1	2.1	2.1			2.9	2.9	2.9	2.9
	Weston	3	337	21	5.2	5.2	5.2	5.2	5.2	5.2	6.3	6.3	6.3	6.3	6.3	6.3
	Total Annual Control Cost				5	6	8	9	10	12	6	7	10	12	14	16
	Accumulated Total Cost through Nth Year				5	11	19	28	38	50	6	13	23	36	49	65
Major Utility Total	**Total Annual Control Cost**				28	30	56	71	81	87	33	35	66	84	96	104
					-	-	-	-	-	-	-	-	-	-	-	-
	Accumulated Total Cost through Nth Year				28	58	114	185	266	353	33	68	134	219	315	419

Notes:

- Mercury control costs include annualized capital purchase and installation costs plus annual operating and maintenance costs.
- Costs are annualized over equipment lifetime and includes utility rate of return on investment.

"Estimated Cost" - The estimated average costs for installing and operating surrogate mercury control equipment by existing pollution control classes in place at Wisconsin utilities.

"High Cost" - Addresses additional costs on each unit for equipment modification or compensating design alternatives to mitigate potential barriers to achieving the target unit control efficiency.

Statements Provided by Organizations Concerning the Mercury Rules Proposed for Adoption at the June 2003 Natural Resources Board Meeting

clean wisconsin
your environmental voice since 1970
122 State Street, Suite 200, Madison, Wisconsin 53703-2500
Telephone: 608.251.7020 Fax: 608.251.1655
Website: www.cleanwisconsin.org

Statement on the Proposed Mercury Rule

Thank you for the opportunity to address the Board today. I'm Marc Looze and I'm the mercury campaign director for Clean Wisconsin, the group formerly known as Wisconsin's Environmental Decade. I am also the mercury issue chair for the Wisconsin Stewarship Network, a coalition of 50 sporting and environmental groups.

First, I want to thank DNR staff for many years of hard work to develop a mercury reduction rule and the Natural Resources Board for your leadership on mercury. I ask for your continued leadership in adopting a mercury rule that is stronger than what is proposed today.

It is very difficult to support the rule draft that is before the Board. My organization helped write the citizen petition to the DNR. In it, we requested a 90% reduction in mercury pollution from power plants and all sources of mercury 10 pounds and greater by 2010.

We realize that some compromise is necessary, which is why we supported the draft rule that went to public hearing in 2001. That rule was a compromise which contained numerous provisions that were weaker than what the citizen petition requested. The current rule draft is far from a compromise.

Today, we're left with an 80% reduction of mercury in power plants' fuel content by 2015. Given that the average utility achieves 15-20% reductions from mercury in fuel already, it is misleading to categorize the reduction as 80%. It is much more like a 60-65% reduction, and that's simply not enough to deliver the much needed benefits to Wisconsin lakes, fish and people.

Let's remember why we're here today: mercury poisoning threatens our childrens' health. The National Academy of Sciences estimates that 60,000 children are born in the US each year that may suffer in school because their mothers ate mercury-contaminated fish. Just looking at population numbers, that's 1200 children born in our state each year that may suffer the same fate. The Centers for Disease Control and Prevention found that 8% of women have mercury levels in their blood that are above the EPA's safe health threshold, meaning children born to those women are at risk for mercury poisoning.

Utilities and their industry trade groups have and always will use the same arguments against reducing pollution: It costs too much. We can't do it. We'll have to shut the lights off. We'll scare businesses away. It seems that in virtually every case, they've been proven wrong.

-OVER-

I'm here today to respectfully ask you to reject those old arguments. I'm here to ask you to support strengthening the proposed mercury rule to include:

- **A 90% reduction of current mercury pollution from coal plants**

- **A measurement of mercury reductions from what is coming out of power plant smokestacks, NOT from the mercury that is in the coal**

- **A 150% offset for new sources of mercury**
  If our goal is to make fish safe to eat for everyone in the future, we can't just clean up existing sources of mercury pollution and replace them with new mercury polluters, like large coal-fired power plants that will be around for 40-50 years.

These provisions were supported in public comment and should be reinserted into the rule before it is adopted by the Board today.

We are optimistic about reducing families' exposure to mercury. A recent study by a DNR researcher in Northern Wisconsin found that regional reductions in mercury deposition can have rapid effects on mercury levels in fish.

We've seen many industries, from paint to batteries, drastically reduce or entirely eliminate mercury usage and emissions. It's time for power companies to do the same and share the responsibility of protecting the health of families and our natural resources from the harmful effects of mercury.

Thank you for your consideration of our requests and for the opportunity to speak.

WI Stewardship Network
Member Organizations

March, 2003

- Audubon Society — Aldo Leopold
- Audubon Society — Madison
- Badger Fly Fishers
- Citizens for a Scenic Wisconsin
- Concerned Citizens of Newport
- ECCOLA
- Families and Friends for Social Responsibility
- Friends of the Jump River
- Habitat Education Center
- Izaak Walton League — WI Division
- Lake Superior Greens
- Menomonee Valley Partners
- Midwest Environmental Advocates
- Mining Impact Coalition
- Musky Club of Wisconsin
- Neighbors Standing United
- Northern Thunder
- Pheasants Forever — Sugar River Valley Chapter
- Plover River Alliance
- Protect the Earth/Anishinaabe Niijii
- Random Lake Association
- River Alliance of Wisconsin
- Sierra Club — John Muir Chapter
- Smallmouth Alliance — Southern WI Chapter
- SOUL
- SOUL of Central Wisconsin
- SOUL of Lake Superior
- SOUL of Rusk County
- Trout Unlimited — Central WI
- Trout Unlimited — Green Bay
- Trout Unlimited — Harry & Laura Nohr
- Trout Unlimited — Hornberg
- Trout Unlimited — Lakeshore
- Trout Unlimited — Shaw-Paca
- Trout Unlimited — Southern WI
- Trout Unlimited — Wolf River
- Twin Lakes Conservancy
- Waterkeepers of Wisconsin
- WI Association of Lakes
- WI B.A.S.S. Federation
- WI League of Conservation Voters
- WI State Council of Trout Unlimited
- WI Wetlands Association
- Wisconsin's Environmental Decade
- WISPIRG

MERCURY MAN

Although children and fetuses are the most at risk from mercury poisoning, there is at least one person who would warn adults to be careful how many and which fish from Wisconsin waters they eat too. That person is Henry (Buddy) Henk Jr. He learned the hard way—real hard.

The headline in the March 3rd 1993 edition of the Duluth News-Tribune read "Love of fish almost kills man." Buddy Henk always loved fish—he'd eat fish every chance he had. "I'd eat fish for two or three meals in a day and then snack on pickled fish while watching TV the way other people snack on potato chips," remarked Henk. "I was a regular Swede."

Henk especially liked eating northerns and got nearly all of his northerns from Windago Lake just a couple miles from his home south of Hayward in Sawyer Co. Windago Lake is one of the 275 lakes on the DNR's health advisory listing of lakes with unsafe levels of mercury in some of the fish. Henk's fish eating frenzy apparently peaked in December of 1991 when he ate more than 40 northerns ranging in size from 18 to 32 inches, all from Windago Lake. The DNR's health advisory recommends that no one eat more than 26 meals of 18 to 22 inch Windago Lake Northerns in a year, and no more than 13 of those meals in any one month. Fish over 26 inches should be eaten less often.

Just two months later, Henk was already feeling the adverse affect, apparently, of his high-fish diet. Between February and November of 1992 Henk experienced sores that wouldn't heal, tremendous leg and back pain, eventual loss of all feeling in his legs and a 100 pound weight loss. He stopped eating fish for the same reason he stopped eating nearly everything—he had no appetite and his throat muscles had atrophied to the point where he couldn't swallow anything but soft cereal. His body was deteriorating quickly. "He was a dying man," said Henk's wife Sue.

Photo courtesy of Terry Boettcher

His mind was deteriorating too. Henk checked into two hospitals over this period; the second was St. Mary's Medical Center in Duluth on November 3rd. There Henk suffered hallucinations. "I was flying planes in bed. I went crazy. They had to restrain me with a straight jacket. I didn't recognize my own wife. I ground my teeth down to the bone," said Henk.

Doctors in Duluth performed a litany of tests on Henk. Tests on his blood, his urine , his spinal fluid—a nerve biopsy test, muscle and nervous reaction tests. All tests came back negative. While discussing the puzzling diagnosis effort with a nurse, Henk's wife mentioned his affinity for fish. Doctors sent a sample of Henk's hair to the Mayo Clinic in Rochester Minnesota for mercury testing. It came back showing an elevated mercury level, though not as high as the doctors might have expected given his extreme symptoms. The next day Henk's bedside chart read "severe mercury toxicity," and doctors began to give him D-Penicillamine, a drug that draws mercury out of the body tissue. Within days the symptoms began reversing—his appetite returned, the hallucinations stopped and the restraints were removed. After several weeks of physical therapy and rehabilitation at Miller-Down Medical Center, Henk returned home on December 23rd 1992 for long-term recuperation.

Public health officials in Wisconsin could not make a definitive finding to confirm that Henk's case was one of acute mercury poisoning because blood tests for mercury were not drawn prior to treatment and while Henk was eating fish. Hair tests for mercury levels can be quite variable, and therefore, are not considered as reliable as blood. But if you ask Buddy Henk, he laughs and says there's no doubt it was mercury poisoning: "I don't recommend that diet to anyone," said Henk.

Henk blames himself though because he knew Lake Windago was on the DNR's fish advisory when he was eating the northerns from it. He wants others to know too. "I think they should put a sign up at each boat landing—they have two signs up to protect the loons," said Henk. "If it keeps one person from going through what I went through I'd be worth it."

Source: "Area man says mercury-tainted fish almost killed him," March 10, 1993, Terrell Boettcher, Sawyer County Record; "Love of fish almost kills man," March 3, 1993, Susan Stanich, Duluth News-Tribune; Buddy Henk, personal communication.

Forest County Potawatomi Community
P.O. BOX 340 • Crandon, WI 54520

Testimony to the Wisconsin Department of Natural Resources Board
Proposed Rules on Mercury Emissions
CR 01-081
June 25, 2003

Thank you, board members, for the opportunity to testify today on the Department of Natural Resources' proposed rules limiting mercury emissions from power plants.

I am Bill McClenahan, of Martin Schreiber & Associates. I was honored to represent the Forest County Potawatomi Community on the DNR's Mercury Citizen Advisory Committee. On behalf of the Potawatomi, I am here to support this rule, but to strongly recommend two changes:

(1) To base required reductions on current ***emissions***, not fuel content, and

(2) To require offsets for ***new*** utility sources of mercury in the rule.

The Potawatomi tribe endorses strong and effective restrictions on mercury emissions. The tribe wants you to know that a substantial majority of people in Wisconsin agree.

In April 2002, the Potawatomi asked this poll question of 600 people. The question includes utility objections to the mercury rule and the fact that it may cost people money:

> Mercury in air pollution from coal-fired power plants and other sources ends up in Wisconsin lakes, leading to government recommendations that people should limit the amount of fish they eat from Wisconsin lakes. State utilities argue that mercury also comes into Wisconsin from other states and that limiting their mercury emissions from Wisconsin power plants

would increase the cost of electricity. Do you support or oppose strict reductions of mercury emissions by utilities and other sources?

73.0% of the people we asked supported the strict reduction of mercury emissions. Only 19.5% opposed them. Support was strong across the board, regardless of geography, party affiliation, income or gender.

The Potawatomi tribe's interest in this rule stems from its tradition of environmental stewardship – a belief that we are all the keepers of the earth for our children and our children's children. It is the responsibility of all of us to protect and preserve our water, our air and our land for future generations.

The tribe is also interested because mercury emissions into the air, and the subsequent contamination of waters, reduce the opportunity for tribal members to participate in traditional practices that depend on clean resources, such as hunting, fishing, cultural, religious and medicinal practices.

In addition, tribal enterprises rely on tourism. Protection of our natural resources is essential to the continued success of tourism in Northern Wisconsin.

The Potawatomi also have a special interest in the mercury issue because they are participating with the DNR in a study of the impacts of mercury deposition in Wisconsin lakes. The tribe is working with Dr. Carl Watras to test levels of mercury in Devil's Lake on the Potawatomi reservation in Forest County. This testing is being done as a result of the tribe's Class I air agreement with the DNR.

The levels of mercury being found at Devil's Lake are a cause for great concern. They are similar or higher than the levels found at other lakes where methylmercury is being found to bioaccumulate in the muscle of fish. People often think of PCBs accumulating in lipids, and cut away the fatty parts of fish, hoping to reduce the amount of mercury they eat. But mercury is accumulating in the ***muscle*** of fish – the meat of the fish that people eat.

This is a major human health issue for our reservation, for Wisconsin and for our nation. The fact that the impacts of mercury often hit children the hardest emphasizes the need for action. We must take action for our children and for the children of generations to come. But we must act to protect our Mother Earth.

We are encouraged, however, by evidence that taking action can and will yield results. Dr. Watras has evidence that Wisconsin lakes respond quickly and positively to changes in atmospheric mercury deposition.

But I also want to emphasize that the tribe rejects any suggestion that our responsibility to the environment ends at Wisconsin's borders. Polluting the air or water of our neighbors is no more ethical than polluting the water where we live. It is also important to remember that the fish we eat (and others eat) do not just come from Wisconsin waters – they come from lakes and rivers and oceans around the world. We must stop the emissions of poisons that end up in those fish.

For these reasons, we support the proposed rule. The Potawatomi urge the state to enact strict limits on mercury emissions – not just to protect the environment from our own emissions, but to set a standard for the federal government to duplicate when it adopts its own mercury regulations.

But the tribe objects to the loophole that would base mercury reductions on the mercury ***content*** of the fuel. Reductions should be made from the current baseline of mercury ***emissions***, as under the proposal that previously went to hearing.

We also object to the exemption for ***new*** sources of mercury. Why should we carve out new coal plants and exclude them from the new state regulations? Again, we urge the board to return to the previous version of the rule and to require utilities to achieve further reductions in existing emissions if they want to build a new power plant that puts mercury into our environment.

The Potawatomi tribe, like the general population of Wisconsin, wants an environment that is healthy for fish, for animals and for our children. So please vote today to endorse strong and effective restrictions on mercury emissions.

Thank you for the opportunity to testify.