State of Wisconsin
Department of Administration
Division of Energy

Focus on Energy Public Benefits Evaluation

Estimating Seasonal and Peak Environmental Emissions Factors—Final Report

May 21, 2004

Evaluation Contractor: PA Government Services Inc.

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PA Government Services Inc.
Middleton, Wisconsin; Washington, D.C.

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REPORT SUMMARY

This report documents a revised model for estimating emissions savings for nitrogen oxides (NOx), sulfur oxides (SOx), carbon dioxide (CO_2), and mercury (Hg) from Focus on Energy efficiency efforts. The report covers four key areas:

1. Improved yearly emissions factors for calculating emission reduction as a result of Focus on Energy activity.
2. Emission factors for on-peak and off-peak energy savings during the winter, summer, and shoulder months.
3. Estimates of the potential value of tradable emission credits produced by Focus on Energy.
4. A discussion of emissions trading.

The emission factors can be multiplied by the energy savings from Focus efforts to calculate total emissions avoided by the Focus efficiency programs. The new yearly emissions factors represent an improvement over the factors used to date, which were developed during the Pilot Focus on Energy program. (This report does not address calculating net emissions for biomass-based renewable generation, which would need to account for emissions from the renewable generation as well as avoided emissions from utility power plants.) The seasonal and peak emission factors will support policy and program design discussions about how to effectively design energy efficiency programs, specifically whether and if so how to modify the design or targeting of programs to maximize emission reductions. The revised model allows us to take into account differences across measures and programs in the distribution of energy impacts over different periods, and thus in the magnitude of emissions reductions per unit of investment.

The yearly emissions factors calculated by our emissions model are shown in Table 1. The “1999 Report” values are those that have been used to date by the evaluation for estimating emission reduction from Focus activities. The “2004 Report” values are the outcome of the revised model presented in this report. (The 1999 report did not include a mercury emission factor.)

Table 1. YEARLY EMISSIONS FACTORS

			Pounds /MWh			Pounds /GWh
Source	**Year of Data**	**Type**	**NOx**	**SOx**	**CO_2**	**Mercury**
1999 Report	1999	By Marginal Cost	6.4	10.8	2,400	
1999 Report	1999	By Capacity Factor	5.9	10.0	2,035	
1998 EPA	1998					0.0373
2004 Report	**2000**		**5.7**	**12.2**	**2,216**	**0.0489**

Sources:
1999 Report: *Development of Emissions Factors for Quantification of Environmental Benefits*, June 25, 2001. Focus on Energy Pilot Evaluation Report.
1998 EPA: *EPA's E-Grid 2000 Database* for MAIN and MAPP for 1998.
2004 Report: This report.

The season and peak emissions factors calculated by our revised emissions model are shown in Table 2. The model was estimated for three scenarios that defined peak and off-peak hours and summer and winter months. Each scenario is independent of the others. Those scenarios are defined in the footnotes to the following table.

Table 2. SEASONAL AND PEAK EMISSIONS FACTORS–SUMMARY

	Pounds /MWh			Pounds /GWh	Percent of Yearly Value			
Season and Hour	**NOx**	**SOx**	**CO_2**	**Mercury**	**NOx**	**SOx**	**CO_2**	**Mercury**
Yearly	5.7	12.2	2,216	0.0489				
Broad Peak Scenario								
Winter Peak	5.9	13.9	2,027	0.0427	104%	114%	91%	87%
Winter Off-peak	5.8	14.5	2,287	0.0536	102%	119%	103%	110%
Summer Peak	4.6	9.8	1,788	0.0346	81%	80%	81%	71%
Summer Off-peak	5.4	11.1	2,233	0.0524	95%	91%	101%	107%
Narrow Peak Scenario								
Winter Peak				No winter peak hours				
Winter Off-peak	5.1	11.0	2,076	0.0461	89%	90%	94%	94%
Summer Peak	2.9	6.0	1,476	0.0181	51%	49%	67%	37%
Summer Off-peak	5.4	11.2	2,073	0.0431	95%	92%	94%	88%
Shoulder Scenario								
Shoulder Peak	5.0	10.4	2,186	0.0510	88%	85%	99%	104%
Shoulder Off-peak	7.1	16.2	2,269	0.0547	125%	133%	102%	112%
Non-shoulder Peak	4.8	11.1	1,945	0.0395	84%	91%	88%	81%
Non-shoulder Off-peak	5.9	13.5	2,260	0.0517	104%	111%	102%	106%

Scenarios:
"Broad Peak:" Summer Peak is April–September 8 am–10 pm workdays. Winter Peak is October–March 7 am–10 pm workdays.
"Narrow Peak:" Summer Peak is June–August 1 pm–4 pm workdays. All other hours are off-peak.
"Shoulder:" Shoulder is March, April, and October; peak is 7 am to 10 pm workdays.

There is a fairly significant range in emissions impacts across technologies for both Residential and Business Programs. As a result, it would be possible to modify program designs to optimize a program's impact on emissions. The key conclusion from the season and peak analysis is that the highest emissions occur in off-peak hours and the lowest in on-peak hours. This is consistent with the general observation that coal provides most of Wisconsin's base load generation (ignoring nuclear and hydro since they emit no NOx, SOx, etc.) and natural gas plants are used more often as peaking plants. These results imply that any effort to maximize a program's emissions impacts will have to be balanced with the program's effort to reduce peak demand.[1]

[1] See Erickson et al. 2004 ACEEE paper listed in references at the end of this report for a discussion of comparing the value of emissions reduction to the value of demand reduction.

Markets exist for emission allowances for NOx and SOx allocated under national and regional cap and trade systems. There is also a fledgling market for CO_2 allowances in the U.S., although there are no regional or national caps on CO_2. There are no caps and no test market in the U.S. for mercury. However there are estimates of the value mercury emission allowances may reach under proposed legislation. Using actual or estimated allowance prices, we can estimate the potential market value of the emissions avoided because of the Focus efficiency programs. Using program impacts through September 30, 2003, and the Broad Peak emission factors the Focus program has reduced emissions with a potential market value of more than $4.6 million. Whether the Focus-produced emissions reductions are marketable and who would receive the proceeds of a sale are complex issues that must be addressed before too much faith is placed in the potential value of the avoided emissions.

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1. EXECUTIVE SUMMARY

This report documents a revised model for estimating emissions savings from Focus on Energy efficiency efforts. The report covers four key areas:

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2. Emission factors for on-peak and off-peak energy savings during the winter, summer, and shoulder months.
3. Estimates of the potential value of tradable emission credits produced by Focus on Energy.
4. A discussion of emissions trading.

This report does not address calculating net emissions for biomass-based renewable generation, which would need to account for emissions from the renewable generation as well as avoided emissions from utility power plants.

The new yearly emissions factors represent an improvement over the factors used to date, which were developed during the Pilot Focus on Energy program. The seasonal and peak emission factors will support policy and program design discussions about how to effectively design energy efficiency programs, specifically whether and if so how to modify the design or targeting of programs to maximize emission reductions. The revised model allows us to take into account differences across measures and programs in the distribution of energy impacts over different periods, and thus in the magnitude of emissions reductions per unit of investment.

The emissions factors produced by the revised model are for nitrogen oxides (NOx), sulfur oxides (SOx), carbon dioxide (CO_2), and mercury (Hg). The report also discusses CO_2 emissions savings from participant-level natural gas savings.

Generation emission factors are expressed in pounds of pollutant per MWh or GWh. These factors can be multiplied by the energy savings from Focus efforts to calculate total emissions avoided by the Focus efficiency programs. The calculations assume that the energy savings results in reduced generation at the power plant for those power plants operating at the margin during a particular time of day or season. The calculations also assume that reduced generation is perfectly correlated with reduced emissions. (This assumption may not always hold true, as will be discussed.)

Enhancements to Yearly Emission Factors: The emissions model presented in this report is an enhancement to a model created by the evaluation team under the Pilot Focus program.[2] That model uses yearly plant-level data on fuels, emissions rates, capacity factors,

[2] *Development of Emissions Factors For Quantification of Environmental Benefits.* PA Consulting Group Report for the Wisconsin Department of Administration, Division of Energy Focus on Energy statewide evaluation. June 25, 2001.

and costs along with the total system hourly load curve to estimate emissions from marginal producers—who are the producers likely to be affected by the Focus program. The model produces reasonably accurate ***yearly*** emissions factors because, on average, it can correctly identify marginal producers. The revised model uses hourly data EPA collects to monitor emissions at power plants.[3] This data contains hourly data on generation and measured emissions of pollutants from all large generators in the country.[4] Thus while the Pilot model estimates emissions based on emission rates and control technologies the revised model uses actual plant emissions, not estimated emissions, which should lead to more accurate emission factors.

Peak and Season Emission Factors: One of the goals of Focus on Energy is to produce environmental benefits from energy efficiency projects, primarily in the form of reduced emissions either at the power plant or at the participant's individual location. If an intervention in the market is to be designed specifically to reduce emissions, it might make sense to target measures that produce savings during seasons and times where the marginal power plants are particularly dirty—that is times when the marginal plants are those that produce the most emissions per MWh. (This assumes that Focus savings will primarily affect marginal power plants, not base-load generators.) If such targeting were attempted, we would need to know the emission factors for various peak and season definitions to know when the emissions were at their highest. To support an exploration of the possible value of this kind of targeting, the evaluation team enhanced the emissions model to produce season and peak emission factors.

The Pilot model does not "know" which plants are actually generating at any given hour of the year, it estimates that given sizes, costs, and/or capacity factors. As a result, the Pilot model could not estimate emissions from parts of the year such as the summer peak hours. To create a time-of-day and season emissions factors, we revised the model and incorporated ***hourly*** monitored emissions and power generation data from the EPA data discussed above. The revised model identifies plants that were actually operating in the specified seasons and times, predicts which were the marginal producers, and then calculates emission factors from all marginal producers.

Mercury: The revised emissions model also includes one other significant advance on the Pilot model by calculating an emissions factor for mercury. The EPA data do not contain measured hourly mercury emissions. As a result, to enable calculating seasonal and peak mercury emissions, the model uses the hourly generation, fuel, and emissions control data to estimate hourly mercury emissions.

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[3] Source: Environmental Protection Agency Office of Air and Radiation. "Acid Rain/OTC Program Hourly Emissions Data." http://www.epa.gov/airmarkets/emissions/raw/index.html

[4] Generally, units required to report to this system burn fossil fuel (coal, oil, natural gas, or any fuel derived from those fuels) to generate and sell electricity and serve a generator that is greater than 25 MW in capacity. See Miller, Robert. 2002 in references.

1.1 CAVEATS AND LIMITATIONS

The basic premise behind the emissions model is that Focus on Energy efforts reduce consumption of electricity, which in turn reduces emissions created by generating that electricity, and Wisconsin residents benefit from the reduced emissions. There are some theoretical and practical limitations that affect how accurate that basic premise is.

Generator Location. The revised model (and the Pilot model) calculates emission factors using data from all plants in the MAIN and MAPP NERC Regions. The State of Wisconsin is primarily supplied by power plants in the Mid-America Interpol Network (MAIN) region, though parts of the state are supplied by plants in the Mid-Continent Area Power Pool (MAPP) region. We could run the model including only power plants sited in Wisconsin and generate Wisconsin-only emission factors (we discuss this option in Chapter 6). However, due to the interconnected nature of the electricity grid, we cannot know with certainty that reduced demand in Wisconsin results in reduced generation from power plants located within Wisconsin. Reduced demand likely will reduce generation within the MAIN or MAPP regions or within the system controlled by the Midwest ISO, the independent transmission system operator that serves the electrical transmission needs of much of the Midwest. As a result, restricting the model to Wisconsin generators would not necessarily correctly model actual emissions reductions.

Does reduced local demand lead to reduced local generation? A second issue touches a similar point: as Focus on Energy efforts reduce demand for power in Wisconsin, does that reduce generation by Wisconsin generators or does it mean that the generators continue operating as before but Wisconsin utilities sell more power out of state? Or do generators faced with reduced demand dial down their pollution control systems to maintain a constant level of emissions while improving operating efficiency? In either case, the calculated emissions reduction would not materialize within Wisconsin's borders. Such situations would produce economic benefits for Wisconsin but it might mean that the benefits of the emission reductions estimated by our model would not be enjoyed by Wisconsin residents unless the power plants were close to our border and upwind.

Trade Winds. NOx, SOx, and mercury produced by power generators can create local environmental problems if they remain in or drift to the local area. For example, reduced demand in Wisconsin that affects Minnesota power plants on the Wisconsin–Minnesota border might reduce pollution in Wisconsin, whereas reduced demand for power from plants on the shores of Lake Michigan may benefit Michigan or Illinois more than Wisconsin. Generator location is not relevant for CO_2 emissions, since CO_2 emissions relate to global warming, whose effects are felt no matter where the CO_2 is produced.

The problem of where the emission reduction benefits are felt is not unique to the model presented in this report—it is a problem that faces most attempts to calculate avoided generation emissions from energy efficiency projects. There is no simple solution to this problem, although we discuss some options in Chapter 6. In an ideal world, Wisconsin's emissions benefits exported to neighboring states would be compensated by similar benefits flowing into the state from energy efficiency programs in neighboring states, although the current level of effort in the neighboring states would imply that Wisconsin is a net exporter of benefits.

SOx Cap-and-trade. Wisconsin's investor-owned utilities are included in the federal SOx regulatory structure of the Clean Air Act (acid rain provisions). This structure has created a cap-and-trade system whereby SOx emissions are capped at a specific level and any reduction in emissions in one place likely leads to increased emissions in a different place, within the trading system. In this system, SOx emissions cannot be considered reduced or avoided unless EPA lowers the SOx cap.

Policy Implications. Even though there are a number of caveats about the emissions reductions produced by Focus, policy makers can still feel confident that reduced electricity use caused by Focus is producing positive benefits to society associated with emissions. At a minimum reduced demand for electricity will reduce the costs of meeting emissions caps. If that reduction in costs is reflected in reduced electricity rates, the local community will still benefit. The method of calculating and valuing emissions reductions presented in this report is an appropriate method of valuing the emissions-related benefits that Focus produces, even if those benefits are achieved in some other location or reflected in increased operating efficiency rather than reduced local emissions.

1.2 NEW GENERATION EMISSIONS FACTORS

The yearly emissions factors calculated by our emissions model are shown in Table 1-1. The “1999 Report” values are those that have been used to date by the evaluation for estimating emission reduction from Focus activities. The “2004 Report” values are the outcomes of the revised model presented in this report. The yearly factor for NOx and CO_2 are somewhat smaller than the previous values and the SOx value is somewhat higher. (The 1999 report did not include a mercury emission factor.)

Table 1-1. YEARLY EMISSIONS FACTORS

			Pounds /MWh			Pounds /GWh
Source	**Year of Data**	**Type**	**NOx**	**SOx**	**CO_2**	**Mercury**
1999 Report	1999	By Marginal Cost	6.4	10.8	2,400	
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Sources:
1999 Report: *Development of Emissions Factors for Quantification of Environmental Benefits*, June 25, 2001. Focus on Energy Pilot Evaluation Report.
1998 EPA: EPA's *E-GRID 2000 Database* for MAIN and MAPP for 1998.
2004 Report: This report.

We examined emissions from generators operating at the margin in four time periods: “Yearly,” “Broad Peak,” “Narrow Peak,” and “Shoulder.” Each scenario is independent of the others. These time periods are defined as follows:

Table 1-2. SEASON AND PEAK SCENARIOS

Scenario	Season	Summer Peak Hours*	Winter Peak Hours*
Broad Peak (Base Case)	April–September = Summer Months	8 am–10 pm	7 am–10 pm
Narrow Peak	June–August = Summer Months	1 pm–4 pm	None
Shoulder	March, April, October = Shoulder Months	7 am–10 pm	7 am–10 pm
Yearly	January – December	No peak hours defined	

* All peak hours are for workdays only, not including weekends.

The seasonal and peak emissions factors calculated by our emissions model are shown in Table 1-3.

Table 1-3. EMISSIONS FACTORS–SUMMARY

	Pounds /MWh			Pounds /GWh	Percent of Yearly Value			
Season and Hour	**NOx**	**SOx**	**CO_2**	**Mercury**	**NOx**	**SOx**	**CO_2**	**Mercury**
Yearly	5.7	12.2	2,216	0.0489				
Broad Peak Scenario								
Winter Peak	5.9	13.9	2,027	0.0427	104%	114%	91%	87%
Winter Off-peak	5.8	14.5	2,287	0.0536	102%	119%	103%	110%
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Winter Peak				No winter peak hours				
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Shoulder Peak	5.0	10.4	2,186	0.0510	88%	85%	99%	104%
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Scenarios:
"Broad Peak:" Summer Peak is April–September 8 am–10 pm workdays. Winter Peak is October–March 7 am–10 pm workdays.
"Narrow Peak:" Summer Peak is June–August 1 pm–4 pm workdays. All other hours are off-peak.
"Shoulder:" Shoulder is March, April, and October; peak is 7 am to 10 pm workdays.

The emissions model calculates the emissions by the generator that is most likely operating on the margin during each hour of the year in the combined MAIN and MAPP regions. The marginal generator is the last generator called upon to meet current demand – it is in a sense peaking plant at that moment in time. Coal produces the most emissions from the marginal generators in the yearly data (see Table 1-4), followed by natural gas. Utility peaking diesel generators produce a sizeable fraction of the CO_2. Coal produces significantly more emissions per MWh than the other fuels for all but CO_2 (Table 1-5).

Table 1-4. CONTRIBUTION OF FUELS TO MARGINAL EMISSIONS–YEARLY MODEL

	Percent of Total Emissions			
Fuel	**NOx**	**SOx**	**CO_2**	**Mercury**
Coal	95.4%	98.6%	87.7%	99.0%
Pipeline Natural Gas †	2.8%	1.1%	6.2%	0.0%
Natural Gas	0.4%	0.1%	0.6%	0.0%
Residual Oil	0.2%	0.0%	0.9%	0.2%
Diesel Oil	1.1%	0.2%	4.6%	0.9%
Total	100.0%	100.0%	100.0%	100.0%

† Pipeline Natural Gas and Natural Gas differ in the amount of hydrogen sulfide (H_2S) they contain with Pipeline Natural Gas having less.

Table 1-5. MEAN EMISSIONS RATE BY FUEL–ALL PLANTS (Not Just Marginal Plants)

		Pounds /MWh		Pounds /GWh
Fuel	**NOx**	**SOx**	**CO_2**	**Mercury**
Coal	5.68	11.63	2,270	0.0541
Pipeline Natural Gas	1.78	0.25	1,451	0.0000
Natural Gas	3.20	2.98	1,816	0.0000
Residual Oil	0.57	0.25	420	0.0016
Diesel Oil	2.27	1.50	906	0.0068
Total	4.22	7.51	1,889	0.0344

Comparison of the Three Scenarios. The lowest emissions rates of any scenario are in the summer peak hours in the Narrow Peak scenario—or between 1 pm and 4 pm between June and August—which is DOA's definition of the peak season. The highest emissions rates are in the shoulder off-peak hours of the Shoulder scenario—or nighttime in March, April, and October. The key determinant of the emissions rates is the amount of power supplied by natural gas burning plants. Coal is the predominant fuel source in all hours and seasons (Table 1-6) but natural gas provides the bulk of the peaking power during times of high system peak. Coal produces over 90% of the CO_2 emissions in many season/hour combinations across the three scenarios, however it produces only 51.6% of the CO_2 emissions in the Narrow Peak scenario during Summer Peak hours.

Generally speaking, other fuels (not coal or natural gas and not counting non-emitting sources of power like hydro and nuclear) provide a very small portion of the power at any time of the year and have a fairly small effect on the emissions rates.

Table 1-6. COAL CONTRIBUTION TO MARGINAL CO_2 EMISSIONS BY SCENARIO

	Percent of Total Marginal CO_2 Emissions Produced by Coal-burning Power Plants			
Scenario	**Summer or Non-shoulder Peak**	**Summer or Non-shoulder Off-peak**	**Winter or Shoulder Peak**	**Winter or Shoulder Off-peak**
Broad Peak	76.3%	93.9%	98.8%	99.9%
Narrow Peak	51.6%	82.8%	NA	88.2%
Shoulder	78.4%	93.9%	95.1%	100.0%

1.3 NATURAL GAS ON-SITE USE EMISSIONS FACTORS

The emission factors discussed above are for emissions savings at the electric generator. Other emissions savings occur when energy efficient projects reduce the use of non-electric fuels at the participant's site. The primary site-based fuel (burned at the participant's site rather than at the power generation plant) saved under the Focus program is natural gas. Combustion of natural gas produces a variety of pollutants including CO_2, NOx, N_2O, SOx, PM10, VOC, and CO. With the exception of CO_2, these pollutants are emitted in fairly small quantities.

According to the EPA's Technology Transfer Network Clearinghouse for Inventories & Emission Factors, the emission factor for CO_2 is 11.76 pounds of CO_2 per therm. The Clearinghouse provides a single emission rate for SOx and mercury, as it does for CO_2. (Both the SOx and mercury values are quite small, particularly compared to coal, and as a result are often ignored.) The Clearinghouse provides a range of estimates for NOx that depend on the size and configuration of the boiler. NOx emissions are particularly sensitive to the size, design, and operating conditions of the boiler. Three representative emission rates for NOx are presented in the following table.

Table 1-7. NATURAL GAS ON-SITE USE EMISSION FACTORS

Substance	Pounds Per Therm
CO_2	11.76
SOx	0.0000588
Mercury	0.00000002549
NOx Lower Bound	0.003137
NOx Mid-range	0.009804
NOx Upper Bound	0.027451

Sources:
(1) Compilation of Air Pollutant Emission Factors, AP-42, Fifth Edition, Volume I: Stationary Point and Area.
(2) EPA Technology Transfer Network Clearinghouse for Inventories and Emission Factors.

1.4 VALUE OF EMISSIONS AVOIDED

When the new emission factors are applied to program savings, we can calculate total pounds of emissions avoided because of the Focus efficiency programs. By assigning a value to each pound of emissions avoided, we can calculate the value of avoided emissions created by the Focus efficiency programs. Active markets for emission allowances for NOx and SOx and a pilot market for CO_2 can provide prices for those three substances. There is no current market for mercury emissions allowances so we must use estimates of projected values given an assumed future market. Estimates of the allowance prices are shown in Table 1-8.

Table 1-8. Emission Allowance Prices

Type of Emission	Historical Price (3/2003-2/2004 Average)	Current Price (2/2004)	Projected Price (2010)
SOx	$194/ton	$269/ton	$295-$348/ton
NOx	$3,581/ton	$2,400/ton	$1,573-$1,643/ton
CO_2	N/A	$0.95/ton	$5-$10/ton
Mercury	N/A	N/A	$16,000-$118,053/lb

Note: tons are U.S. short tons and CO_2 is not carbon but tons of CO_2. CO_2 is often denominated in metric tons of carbon but we use short tons of CO_2 to maintain consistency with the other calculations.

Source: Current prices for NOx and SOx: Cantor Environmental Brokerage Market Price Indices. Current price for CO_2: Chicago Climate Exchange. Projected Prices PA Consulting Group M-POM model.

Using the lower bound of the projected prices for emission allowances produces a total value of the avoided emissions created by the Focus efficiency programs of almost $4.7 million (see Table 1-9).

Table 1-9. POUNDS AND VALUE OF EMISSIONS AVOIDED BY PEAK/SEASON AND PROGRAM

	Business Programs				Residential Programs			
Period	**SOx**	**NOx**	**CO_2***	**Hg**	**SOx**	**NOx**	**CO_2***	**Hg**
				Pounds				
Summer Off-peak	444,544	216,265	89,429,423	2.1	300,946	146,406	60,541,736	1.4
Summer Peak	473,349	222,184	86,362,026	1.7	311,951	146,426	56,915,134	1.1
Winter Off-peak	715,544	286,218	112,858,634	2.6	597,750	239,100	94,279,589	2.2
Winter Peak	863,768	366,635	125,961,032	2.7	681,608	289,316	99,397,104	2.1
On-site Natural Gas	757	126,146	151,313,733					
Total	**2,497,206**	**1,091,302**	**414,611,115**	**9.1**	**1,892,255**	**821,248**	**311,133,562**	**6.8**
				Dollars				
Summer Off-peak	65,570	170,092	223,574	33,577	44,390	115,149	151,354	22,731
Summer Peak	69,819	174,748	215,905	26,739	46,013	115,164	142,288	17,622
Winter Off-peak	105,543	225,110	282,147	42,321	88,168	188,052	235,699	35,354
Winter Peak	127,406	288,359	314,903	42,455	100,537	227,547	248,493	33,502
On-site Natural Gas	112	99,214	378,284					
Total	**$368,449**	**$957,523**	**$1,414,812**	**$145,092**	**$279,108**	**$645,912**	**$777,834**	**$109,209**
Program Total	**$2,885,877**				**$1,812,062**			
Focus Total	**$4,697,939**							

Based on program-to-date energy impacts data through September 30, 2003, and the Broad Peak emission factors. Using credit prices of $0.1475/pound for SOx, $0.7865/pound for NOx, and $0.0025/pound for CO_2 and $16,000/pound for mercury.

* The pounds of CO_2 in this table include generation savings and on-site savings from natural gas. [Reference Table 1-3 in Executive Summary.]

1.5 EMISSIONS BANG FOR THE BUCK

There is a fairly significant range in emissions impacts across technologies for both Residential and Business Programs. Annual avoided emissions savings for residential technologies vary from $10.86/MWh to $12.88/MWh. Business technologies vary from $11.40/MWh to $12.93/MWh. As a result, it would be possible to modify program designs to optimize a program's impact on emissions. The key conclusion from the season and peak analysis is that the highest emissions occur in off-peak hours and the lowest in on-peak hours. This is consistent with the general observation that coal provides most of Wisconsin's base load generation (ignoring nuclear and hydro since they emit no NOx, SOx, etc.) and natural gas plants are used more often as peaking plants. These results imply that any effort to maximize a program's emissions impacts will have to be balanced with the program's effort to reduce peak demand.[5]

1.6 POLLUTION ALLOWANCES AND TRADING

Energy savings created by Focus efforts can produce a variety of benefits including financial savings to participants, improved reliability, and health benefits that come from reduced emissions. The magnitude and nature of the potential emissions benefits are affected by a variety of factors discussed in this report. One final factor, and potentially the most important factor, is the regulation of emissions. Emissions of SOx nationwide, and NOx in some states (but not Wisconsin) are currently the subject of caps specified in emission reduction legislation and agreements. CO_2 and mercury may come under such caps in the near future. As a result, any reduction in energy use in one place as an outcome of an energy efficiency program may not actually produce emissions savings in the vicinity. Rather, it might produce savings for the utility in the cost of meeting emissions caps. Even so, DOA and Focus program designers may still choose to target energy efficiency actions to emissions reductions since the value of the emissions will either be represented in actual reduced emissions or in increased operating efficiency for Wisconsin utilities. If that increased efficiency gets reflected in reduced electricity rates, the local community will still benefit. The last chapter will discuss the prospects for stricter air pollution controls and issues of the ownership of pollution allowances that programs like Focus create.

[5] See Erickson et al. 2004 ACEEE paper listed in references at the end of this report for a discussion of comparing the value of emissions reduction to the value of demand reduction.

2. INTRODUCTION

This report documents a revised model for estimating emissions savings from Focus on Energy efficiency efforts. The report covers three key areas:

1. Improved yearly emissions factors for calculating emission reduction as a result of Focus on Energy activity.
2. Emission factors for on-peak and off-peak energy savings during the winter, summer, and shoulder months.
3. Estimates of the potential value of tradable emission credits produced by Focus on Energy.
4. A discussion of emissions trading.

This report does not address calculating net emissions for biomass-based renewable generation, which would need to account for emissions from the renewable generation as well as avoided emissions from utility power plants.

The new yearly emissions factors represent an improvement over the factors used to date, which were developed during the Pilot Focus on Energy program. The seasonal and peak emission factors will support policy and program design discussions about how to effectively design energy efficiency programs, specifically whether and if so how to modify the design or targeting of programs to maximize emission reductions. The revised model allows us to take into account differences across measures and programs in the distribution of energy savings over different periods, and thus in the magnitude of emissions reductions per unit of investment. The discussion of emissions trading provides looks at issues that DOA should address as it considers the emissions benefits produced by the Focus on Energy programs.

The emissions factors produced by the revised model are for nitrogen oxides (NOx), sulfur oxides (SOx), carbon dioxide (CO_2), and mercury (Hg). The report also discusses CO_2 emissions savings from participant-level natural gas savings.

Generation emission factors are expressed in pounds of pollutant per MWh or GWh. These factors can be multiplied by the energy savings from Focus efforts to calculate total emissions avoided by the Focus efficiency programs. The calculations assume that the energy savings results in reduced generation at the power plant for those power plants operating at the margin during a particular time of day or season. The calculations also assume that reduced generation is perfectly correlated with reduced emissions. (This assumption may not always hold true, as will be discussed.)

This chapter will introduce the purpose and goals of the effort and outline the chapters to follow.

2.1 THE ISSUE

One of the objectives of the evaluation of Focus on Energy is to quantify the environmental benefits associated with the energy impacts of the Focus programs. The environmental benefits are produced in two ways. First, reduced electricity consumption or on-site electricity generation at the individual participant level results in reduced generation at one of the power plants feeding Wisconsin. That reduced generation implies reduced emissions at the power plant. Second, improved efficiency at the individual participant level sometimes reduces on-site consumption of non-electric fuels, typically natural gas but possibly fuel oil, diesel, or a number of other fuels including those from renewable sources. Calculating total emission reduction from all Focus efforts involves summing electricity savings and on-site fuel savings then multiplying those savings by emission factors to produce pounds of emissions saved or avoided. For our purposes, the emission factors are expressed as pounds of pollutant per MWh of electricity or per therm of natural gas.[6]

In the simplest form, calculating emission savings uses the following formula:

Energy saved * Emission factor = Pounds of pollutant avoided.

Other evaluation activities and reports address the size and reliability of the "energy saved" portion of the formula. The primary purpose of this report is to examine ways of improving the "emission factor" part of the formula.

The EPA and others[7] have produced emission factors for Wisconsin. These factors are typically calculated as an average of all generators in the state or region, or of all emitting generators (excluding, for example, hydro and nuclear). As such, they do not take into account two critical aspects. First, given the size of the Focus programs at present, their impact on generators is likely to be felt at the margin, rather than having an effect on base-load plants. In other words, any plant that might be shut off at any given hour because of savings from Focus participants is likely to be a marginal producer, one called into action to meet current changes in demand then shut off, rather than a base-load plant that operates much of the time. The emissions profile of a marginal power producer could be very different from base-load plants so removing it from the generation mix could cause emission savings that differ significantly from the average.

Second, the emission factors produced by others are ***yearly*** averages. They do not tell us anything about emissions avoided at particular times of the year or times during the day. If an intervention in the market is to be designed specifically to reduce emissions, it might make sense to target measures that produce savings during seasons and times where the marginal power plants are particularly dirty—that is times when the marginal plants are those that produce the most emissions per MWh.

To address the first critical aspect discussed above (marginal producers), the evaluation team under the Focus Pilot Program created a model that calculates emission factors from the marginal producers. That effort was documented in the report titled, *Development of*

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[6] In this report, for on-site emission reduction we examine only emissions from natural gas.

[7] See, for example: (1) EPA's *E-Grid 2000 database*. (2) *Compilation of Air Pollutant Emission Factors*, AP-42, Fifth Edition, Volume I: Stationary Point and Area Sources. EPA Technology Transfer Network Clearinghouse for Inventories & Emission Factors. (3) "Emission Factors and Energy Prices for the Cleaner and Greener Environmental Program" by Leonardo Academy (www.leonardoacademy.org).

Emissions Factors for Quantification of Environmental Benefits.[8] The CO_2, NOx, and SOx emissions factors presented in that report have been used to-date by the evaluation team to calculate emission reductions in quarterly evaluation impact reports and in the benefit-cost analysis reports. The Pilot model uses yearly plant-level data on fuels, emissions rates, capacity factors, and costs along with the total system hourly load curve to estimate emissions from marginal producers—who are the producers likely to be affected by the Focus program. The model produces reasonably accurate ***yearly*** emissions factors because, on average, it can correctly identify marginal producers. The revised model uses hourly data EPA collects to monitor emissions at power plants.[9] This data contains hourly data on generation and measured emissions of pollutants from all large generators in the country.[10] Thus while the Pilot model estimates emissions based on emission rates and control technologies the revised model uses actual plant emissions, not estimated emissions, which should lead to more accurate emission factors.

The revised emissions model also addresses the second critical aspect discussed above (seasonal and time-of-day emissions). One of the goals of Focus on Energy is to produce environmental benefits from energy efficiency projects, primarily in the form of reduced emissions either at the power plant or at the participant's individual location. If an intervention in the market is to be designed specifically to reduce emissions, it might make sense to target measures that produce savings during seasons and times where the marginal power plants are particularly dirty—that is times when the marginal plants are those that produce the most emissions per MWh. (This assumes that Focus savings will primarily affect marginal power plants, not base-load generators.) If such targeting were attempted, we would need to know the emission factors for various peak and season definitions to know when the emissions were at their highest. To support an exploration of the possible value of this kind of targeting, the evaluation team enhanced the emissions model to produce season and peak emission factors.

The Pilot model does not "know" which plants are actually generating at any given hour of the year, it estimates that given sizes, costs, and/or capacity factors. As a result, the Pilot model could not estimate emissions from parts of the year such as the summer peak hours. To create a time-of-day and season emissions factors, we revised the model and incorporated ***hourly*** monitored emissions and power generation data from the EPA data discussed above. The revised model identifies plants that were actually operating in the specified seasons and times, predicts which were the marginal producers, and then calculates emission factors from all marginal producers.

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[8] *Development of Emissions Factors For Quantification of Environmental Benefits.* PA Consulting Group Report for the Wisconsin Department of Administration, Division of Energy Focus on Energy statewide evaluation. June 25, 2001.

[9] Source: Environmental Protection Agency Office of Air and Radiation. "Acid Rain/OTC Program Hourly Emissions Data." http://www.epa.gov/airmarkets/emissions/raw/index.html

[10] Generally, units required to report to this system burn fossil fuel (coal, oil, natural gas, or any fuel derived from those fuels) to generate and sell electricity and serve a generator that is greater than 25 MW in capacity. See Miller, Robert. 2002 in references.

The revised emissions model also includes one other significant advance on the Pilot model by calculating an emissions factor for mercury. The EPA data do not contain measured hourly mercury emissions. As a result, to enable calculating seasonal and peak mercury emissions, the model uses the hourly generation, fuel, and emissions control data to estimate hourly mercury emissions.

The report also includes a discussion of CO_2 savings from reduced on-site natural gas use.

2.2 METHOD OVERVIEW AND BENEFITS

The Pilot emissions model uses yearly plant-level data on fuels, emissions rates, capacity factors, and costs along with the total system hourly load curve to estimate emissions from marginal producers. As a result, the model does not "know" which plants are actually generating at any given hour of the year, it estimates that given sizes, costs, and/or capacity factors. The model produces reasonably accurate ***yearly*** emissions factors because, on average, it can correctly identify marginal producers.

Since the Pilot model cannot accurately define which generators are on-line in any given hour, it would be significantly less accurate at estimating emissions from parts of the year such as the summer peak hours. To create a time-of-day and season emissions model, we had to have access to hourly data on each generation plant in the region. The only hourly data available that would meet our needs is data EPA collects to monitor emissions at power plants.[11] This data is primarily an emissions data set—it contains hourly data on actual emissions of pollutants from all large generators in the country.[12] By using this data as the underpinnings of the revised model, we developed a model with the following advantages over the generic averages used by others and over the Pilot model used to date:

- The model calculates emission factors from plants operating on the margin in the specified seasons and times and in the distribution region serving Wisconsin, rather than using averages including all generators in Wisconsin.
- The Pilot model estimates emissions based on emission rates and control technologies while the revised model uses actual plant emissions, not estimated emissions.
- The model uses true time-of-use data, not estimates.

The revised emissions model also includes one other significant advance on the Pilot model by calculating an emissions factor for mercury. Mercury emissions are not tracked in the EPA hourly data but the hourly data contains detailed information on fuels and emissions cleaning technologies. Using that data we were able to estimate hourly mercury emissions which

[11] Source: Environmental Protection Agency Office of Air and Radiation. "Acid Rain/OTC Program Hourly Emissions Data." http://www.epa.gov/airmarkets/emissions/raw/index.html

[12] Generally, units required to report to this system burn fossil fuel (coal, oil, natural gas, or any fuel derived from those fuels) to generate and sell electricity and serve a generator that is greater than 25 MW in capacity. See Miller, Robert. 2002 in references.

enabled us to calculate mercury emission factors using the same basic methods as those used for CO_2, NOx, and SOx. This improvement led to the following advantages of the revised model:

- The coal mercury content is region specific, so the actual mercury going into combustion should be more accurate than national averages.
- Coal quality samples are proximate to the time the fuel was purchased and consumed. The data used in this model more accurately reflects the mercury content of coal being mined and combusted for this year than the EPA emission factors generated under AP-42 (the primary source of emission factors at EPA) does since the samples are from 1999 coal, and the coal was combusted in 2000.
- This method uses the latest information in mercury emissions and coal quality, which should be a more accurate reflection of actual emissions than emissions based on EPA average emission factors, such as those published in AP-42.

2.3 CAVEATS AND LIMITATIONS

The basic premise behind the emissions model is that Focus on Energy efforts reduce consumption of electricity, which in turn reduces emissions created by generating that electricity, and Wisconsin residents benefit from the reduced emissions. There are some theoretical and practical limitations that affect how accurate that basic premise is.

Generator Location. The revised model (and the Pilot model) calculates emission factors using data from all plants in the MAIN and MAPP NERC Regions. The State of Wisconsin is primarily supplied by power plants in the Mid-America Interpol Network (MAIN) region, though parts of the state are supplied by plants in the Mid-continent Area Power Pool (MAPP) region. We could run the model including only power plants sited in Wisconsin and generate Wisconsin-only emission factors (we discuss this option in Chapter 6). However, due to the interconnected nature of the electricity grid, we cannot know with certainty that reduced demand in Wisconsin results in reduced generation from power plants located within Wisconsin. Reduced demand likely will reduce generation within the MAIN or MAPP regions or within the system controlled by the Midwest ISO, the independent transmission system operator that serves the electrical transmission needs of much of the Midwest. As a result, restricting the model to Wisconsin generators would not necessarily correctly model actual emissions reductions.

Does reduced local demand lead to reduced local generation? A second issue touches a similar point: as Focus on Energy efforts reduce demand for power in Wisconsin, does that reduce generation by Wisconsin generators or does it mean that the generators continue operating as before but Wisconsin utilities sell more power out of state? Or do generators faced with reduced demand dial down their pollution control systems to maintain a constant level of emissions while improving operating efficiency? In either case, the calculated emissions reduction would not materialize within Wisconsin's borders. Such situations would produce economic benefits for Wisconsin but it might mean that the benefits of the emission reductions estimated by our model would not be enjoyed by Wisconsin residents unless the power plants were close to our border and upwind.

Trade Winds. NOx, SOx, and mercury produced by power generators can create local environmental problems if they remain in or drift to the local area. For example, reduced demand in Wisconsin that affects Minnesota power plants on the Wisconsin-Minnesota border might reduce pollution in Wisconsin, whereas reduced demand for power from plants on the shores of Lake Michigan may benefit Michigan or Illinois more than Wisconsin. Generator location is not relevant for CO2 emissions, since CO2 emissions relate to global warming, whose effects are felt no matter where the CO2 is produced.

The problem of where the emission reduction benefits are felt is not unique to the model presented in this report—it is a problem that faces most attempts to calculate avoided generation emissions from energy efficiency projects. There is no simple solution to this problem, although we discuss some options in Chapter 6. In an ideal world, Wisconsin's emissions benefits exported to neighboring states would be compensated by similar benefits flowing into the state from energy efficiency programs in neighboring states, although the current level of effort in the neighboring states would imply that Wisconsin is a net exporter of benefits.

SOx Cap-and-trade. Wisconsin's investor-owned utilities are included in the federal SOx regulatory structure of the Clean Air Act (acid rain provisions). This structure has created a cap-and-trade system whereby SOx emissions are capped at a specific level and any reduction in emissions in one place likely leads to increased emissions in a different place, within the trading system. In this system, SOx emissions cannot be considered reduced or avoided unless EPA lowers the SOx cap.

Policy Implications. Even though there are a number of caveats about the emissions reductions produced by Focus, policy makers can still feel confident that reduced electricity use caused by Focus is producing positive benefits to society associated with emissions. At a minimum reduced demand for electricity will reduce the costs of meeting emissions caps. If that reduction in costs is reflected in reduced electricity rates, the local community will still benefit. The method of calculating and valuing emissions reductions presented in this report is an appropriate method of valuing the emissions-related benefits that Focus produces, even if those benefits are achieved in some other location or reflected in increased operating efficiency rather than reduced local emissions.

2.4 POTENTIAL USES FOR THE RESULTS

The revised emissions model supports two efforts:

1. Providing improved estimates of emissions avoided because of the Focus efficiency programs.
2. Provide input into policy and program design discussions.

Regarding effort number 1, at a minimum the full year emission factors produced by this model represent an improvement in accuracy over the factors produced by the Pilot model. The revised emissions factors can be used to support **reporting emission reductions** created by Focus on Energy efforts, as the Pilot emission factors have been used in the past.

The seasonal and peak emission factors produced by the model could also be used to report emissions savings during specified seasons and peaks **provided program energy savings can be accurately reported in times and seasons to correspond to the model's times and seasons.**

Regarding effort number *2*, the seasonal and peak emission factors will support policy and program design discussions about how to effectively design energy efficiency programs, specifically whether and if so how to modify the design or targeting of programs to maximize emission reductions. The revised model allows us to take into account differences across measures and programs in the distribution of energy savings over different periods, and thus in the magnitude of emissions reductions per unit of investment. Program designers could use the new seasonal and peak emission factors combined with information on load patterns for various types of equipment and types of businesses to target program efforts toward those areas that would produce the most emissions reductions for a given level of effort.

Current Focus data collection and reporting systems provide peak demand savings estimates but do not provide information on the seasonality of savings. As a result, if DOA wants emissions savings reported in these categories, then one of two things needs to happen. Either the data collection and reporting systems have to be adjusted to provide that data on a regular basis. Or, a system would have to be developed for periodically translating existing program tracking data into seasonal and peak demand data. (See Chapter 6 for a fuller discussion of what this would involve.) Such a system would have to contain a large number of assumptions or rules so that we could take educated guesses about likely usage patterns. For example, we could assume that residential lighting savings are heavily weighted toward evening hours with more of the savings coming in the winter than in the summer. Such rules of thumb would have to be quantified so that they could be automatically applied to convert yearly savings into peak and season savings.

2.5 ORGANIZATION OF THE REPORT

The following chapter presents an overview of the theory behind the model. It explains in broad terms how the model works and why that approach is appropriate given the goals. Chapter 4 presents the results of the model and compares them to other emission estimates. Chapter 5 uses the new emissions factors to calculate emissions savings in pounds and dollars from Focus efficiency programs. Chapter 6 discusses some areas where future work could answer outstanding questions or further enhance the model. Chapter 7 presents a discussion of the issues around estimating a market or value for avoided emissions.

Appendix A provides detail on how we incorporated mercury in the analysis, since it involved different methods from the other substances. Appendix B provides a projection of emission credit prices that underlies some of the analysis in Chapter 5. Appendix C presents a bibliography of references cited in this report.

3. EMISSION FACTORS THEORY

This chapter presents an overview of the theory behind the model, as follows:

- Introduction,
- Load Duration Curve and Power Plant Dispatch,
- Calculating Emission Factors,
- Calculating Emission Rates for Each Generator, and
- Target Region.

3.1 INTRODUCTION

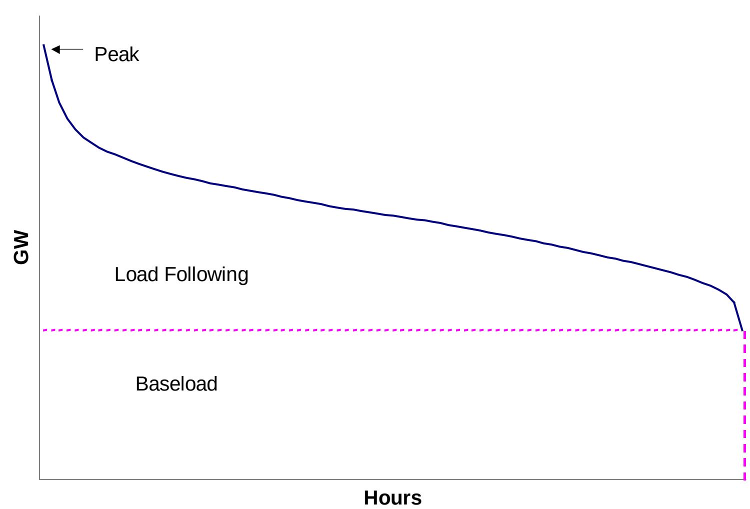
Estimating the emissions that are avoided by programs that reduce electricity use through efficiency improvement requires an emissions rate or factor that represents what would have happened if not for the implementation and effects of the programs. Such estimation hinges upon finding the type of power plants whose use would be avoided by the programs and the emissions avoided by their reduced operation.

The approach described here allows estimation of the power plants that are expected to be the marginal source during a given period. It provides a reasonable estimate of which sources are likely to be curtailed in response to the load reduction from programs.

3.2 LOAD DURATION CURVE AND POWER PLANT DISPATCH

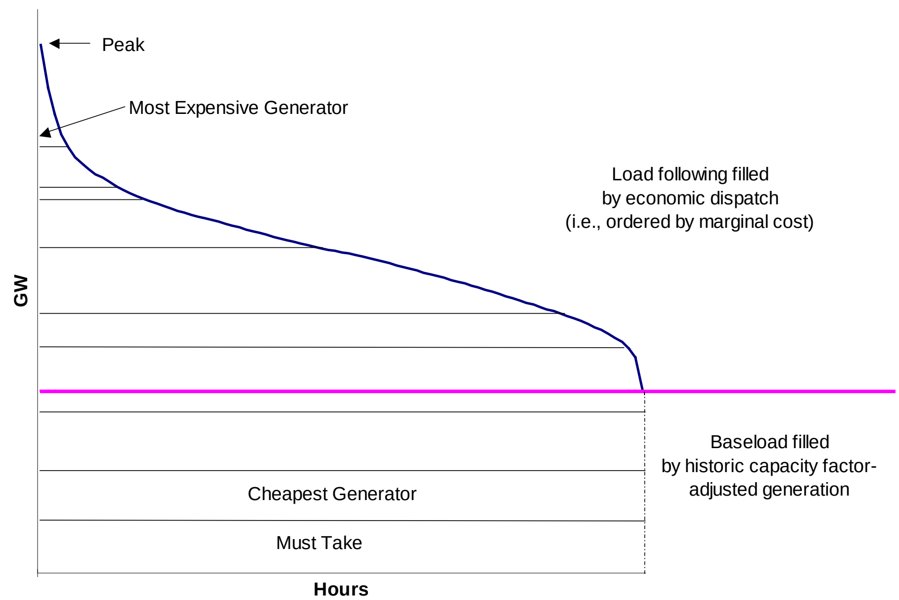
The load of an electricity generation system during a given period can be represented in a diagram that plots system power output as a function of time. In order to clarify the respective roles of different power sources in meeting the load, chronological load data can be converted into a load duration curve. A load duration curve is a reordering of chronological load data into the form of Figure 3-1, in which the x-axis shows how many hours the load was equal to or greater than the power level shown on the y-axis.

Figure 3-1. LOAD DURATION CURVE



For each hour of the year, there is a particular cost-minimizing dispatch of power sources to meet the demand of that hour. In principal, power system dispatchers choose the most cost-effective power plants that can provide power to meet demand at any give hour of the day. In doing so, they fill the area underneath the load duration curve by starting with the most cost effective units and proceeding to the more costly units until they assemble enough power to meet demand. The basic goal of our model is to approximate that dispatch and thereby identify the last plant that is needed to fill demand for each hour of the day (see Figure 3-2). That last plant is the marginal producer for that hour. In theory, if demand were curtailed in a particular hour as a result of an energy efficiency program, that marginal producer would not be needed and the emissions they would have produced would be avoided.

Figure 3-2. LOAD CURVE WITH GENERATOR DISPATCH



Load duration curve is filled from the cheapest to the most expensive generators (except for must-take generation—hydro, wood, and CHP).[13]

Our model approximates economic dispatch (based on marginal cost) by calculating capacity factors for each plant and using the capacity factors to determine which plants are on-line when and for how long. The capacity factor is the ratio of the amount of energy generated by a plant in a period of time divided by the amount of energy it would have produced if it had been operating at full capacity for the entire time period. Our model uses actual hourly generation data to calculate potential generation (maximum capacity) and then capacity factors.

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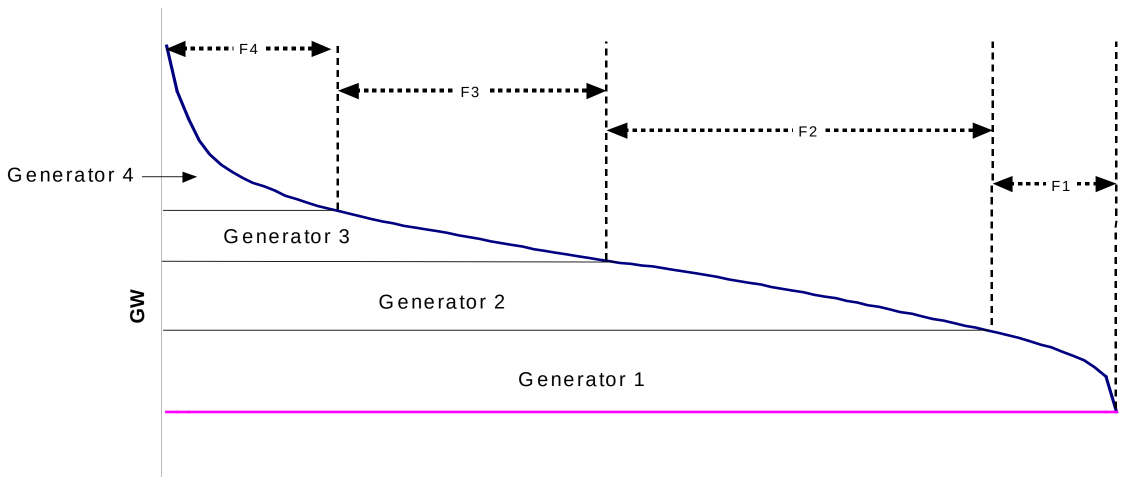
[13] "Must-take" generation is from power plants that for a variety of reasons are always included in the generation mix when they are operating. For example, contracts with some renewable fuels or plants producing combined heat and power (CHP) require the grid to accept their power whenever they are generating.

Simply put we assume that a plant that is producing power at or near its maximum capacity in a given time period is used more often and earlier in the dispatch than a plant that is producing less power than it is capable of producing.

3.3 CALCULATING EMISSION FACTORS

Once the model identifies which plants are producing power at any given hour of the year and which are the marginal producers, it calculates emissions factors by summing the emissions from those operating at the margin and dividing by the energy they produce. The marginal emissions rate for a given pollutant is calculated as the average of the respective emission factors for each source, weighted by the percentage of hours in the period for which each source is marginal (see Figure 3-3).

Figure 3-3. CALCULATION OF MARGINAL EMISSIONS



Marginal emissions rate = $(F_1{*}e_1) + (F_2{*}e_2) + (F_3{*}e_3) + (F_4{*}e_4)$.

F_i = time fraction generator i is marginal.

e_i = emission rate of generator I.

3.4 CALCULATING EMISSION RATES FOR EACH GENERATOR

The model described so far in this chapter corresponds to the Focus Pilot emissions model. This section will describe the theory behind the additional capabilities in the revised model.

The model as defined so far is critically dependent on two pieces of data: the area-wide load duration curve and the plant-specific emissions factors for NOx, SOx, and CO_2. The Pilot model used plant-specific data from EIA's National Energy Modeling System to calculate emissions rates for each plant. This approach was taken to create a simple, straightforward model that provides area-wide emissions factors that could be used to calculate emissions savings from energy efficiency programs. The emissions factors created in this model are applied across full-year savings, regardless of seasonal or daily variations in energy savings patterns. Since some kinds of energy efficiency measures and some kinds of programs are more likely to create energy savings in certain times of the year or certain times of day, it seemed a natural extension of this model to examine emissions on a seasonal and/or peak/off-peak basis. To meet this need we used hourly energy and emissions data from each plant in the region serving Wisconsin to calculate plant-specific emissions factors for peak and off-peak hours in the summer and winter, as discussed below.

The Pilot emissions model uses yearly plant-level data on fuels, heat rates, cleaning technology, and emissions rates in calculating plant-level emission rates. The revised model uses actual hourly measured plant emissions to calculate emission rates. The EPA hourly emissions data used to calibrate the model has plant-specific emissions and energy output values for all large power generators[14] in the region supplying Wisconsin. To calculate an emission rate we summed the emissions and energy use for each plant and then divided the former by the latter, as follows:

$$\text{Pounds of Emissions/MWh} = \frac{\text{Sum of Emissions (Pounds)}}{\text{Sum of Energy Use (MWh).}}$$

The Pilot model calculates average emission factors that can be applied to yearly data. The revised model allows for season and peak differences in emission rates. The revised model calculates emission factors for time periods less than a full year and less than a full 24-hour day. The initial plan was to run the model using the following four periods:

- Peak hours in winter.
- Off-peak hours in winter.
- Peak hours in summer.
- Off-peak hours in summer.

The model was designed to run with any subset of hours and days, for example it could calculate emission factors for each month of the year, for weekends vs. weekdays, or for winter and summer without specifying peak hours. In principal, the chief change to enable this capability is expressed in the following formula, a revision of the formula shown above:

$$\text{Pounds of Emissions/MWh} = \frac{\text{Sum of Emissions } \textbf{in time period} \text{ (Pounds)}}{\text{Sum of Energy Use } \textbf{in time period} \text{ (MWh).}}$$

This formula represents the calculation of factor e_i in Figure 3-3 above.

Parallel to that change was a change in the calculation of the capacity factor used to dispatch plants. The base calculation of capacity factor is as follows:

$$\text{Capacity Factor} = \frac{\text{Sum of Energy Use for the year (MWh)}}{\text{(Maximum MW for the year) * (Hours in the year).}}$$

The revised model changes that formula as follows:

[14] Generally, units required to report to this system burn fossil fuel (coal, oil, natural gas, or any fuel derived from those fuels) to generate and sell electricity and serve a generator that is greater than 25 MW in capacity. See Miller, Robert. 2002 in references.

$$\text{Capacity Factor} = \frac{\text{Sum of Energy Use } \textbf{in time period} \text{ (MWh)}}{\text{(Maximum MW } \textbf{in time period}\text{) * (Hours } \textbf{in time period}\text{).}}$$

The capacity factor is used in calculating factor F_i in Figure 3-3 above.

3.5 TARGET REGION

The EPA data used in our model contains data on generators throughout the United States. The data contains location information so, in principal, our model could be run on any subset of power plants, including only those sited in Wisconsin. We chose to include in the model all plants in the MAIN and MAPP NERC Regions. The State of Wisconsin is primarily supplied by power plants in the Mid-America Interpol Network (MAIN) region, though parts of the state are supplied by plants in the Mid-Continent Area Power Pool (MAPP) region (Figure 3-4). Wisconsin generators are 19% of the generators in MAIN and MAPP or 12% of generators when size is taken into account (weighted by MWh) (Figure 3-5).

We could run the model including only power plants sited in Wisconsin and generate Wisconsin-only emission factors (we discuss this option in Chapter 6). However, due to the interconnected nature of the electricity grid, we cannot know with certainty that reduced demand in Wisconsin results in reduced generation from power plants located within Wisconsin. Reduced demand likely will reduce generation within the MAIN or MAPP regions or within the system controlled by the Midwest ISO, the independent transmission system operator that serves the electrical transmission needs of much of the Midwest. As a result, restricting the model to Wisconsin generators would not necessarily correctly model actual emissions reductions.

One area for future study suggested at the end of this report is the effect on emission factors of using subsets of generators, such as only those sited in Wisconsin. Another area for future study is to examine the likelihood that reduction in demand (because of Focus or from other causes) yields reductions in generation among Wisconsin utilities rather than increased exports of power.

Figure 3-4. NERC POWER DISTRIBUTION REGIONS

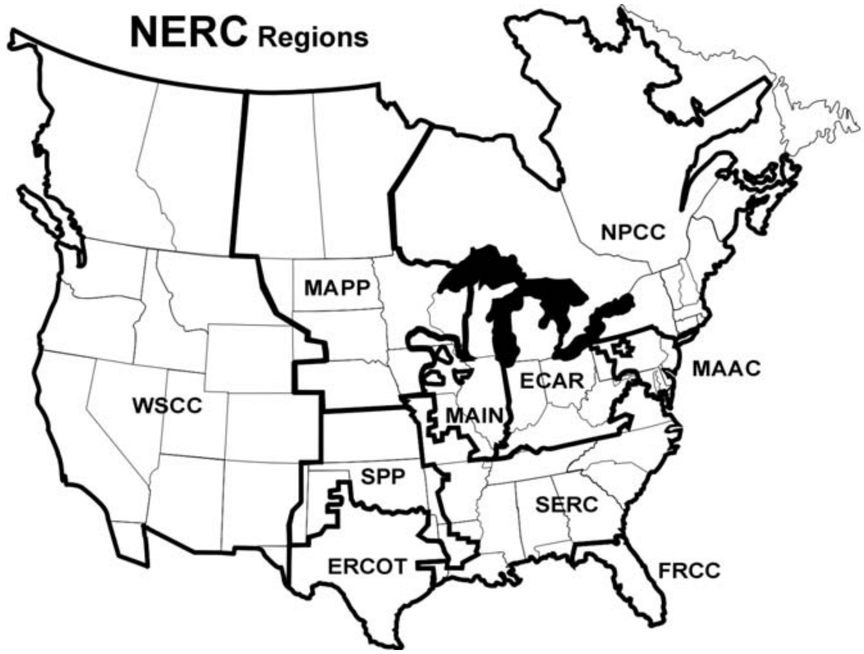
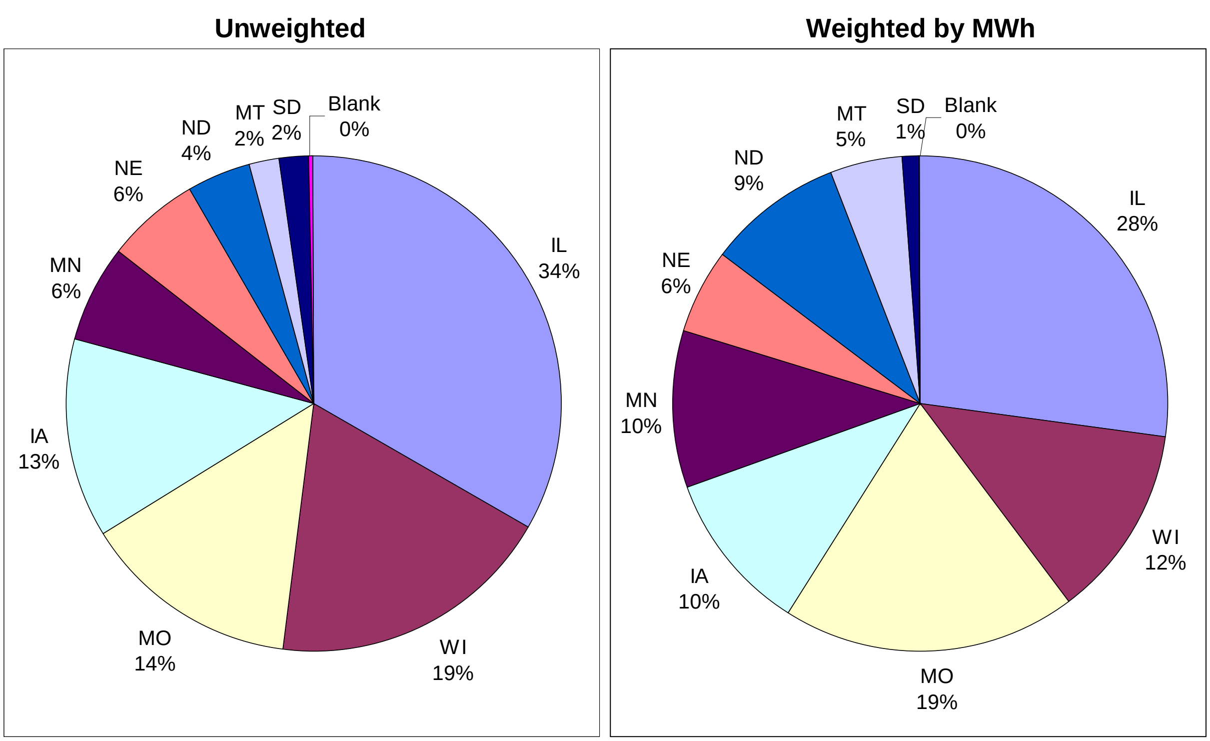


Figure 3-5. PERCENT OF PLANTS IN EMISSIONS DATA BY STATE



Source: Analysis of data in *Acid Rain Hourly Emissions Data 2000*, Environmental Protection Agency Office of Air and Radiation.

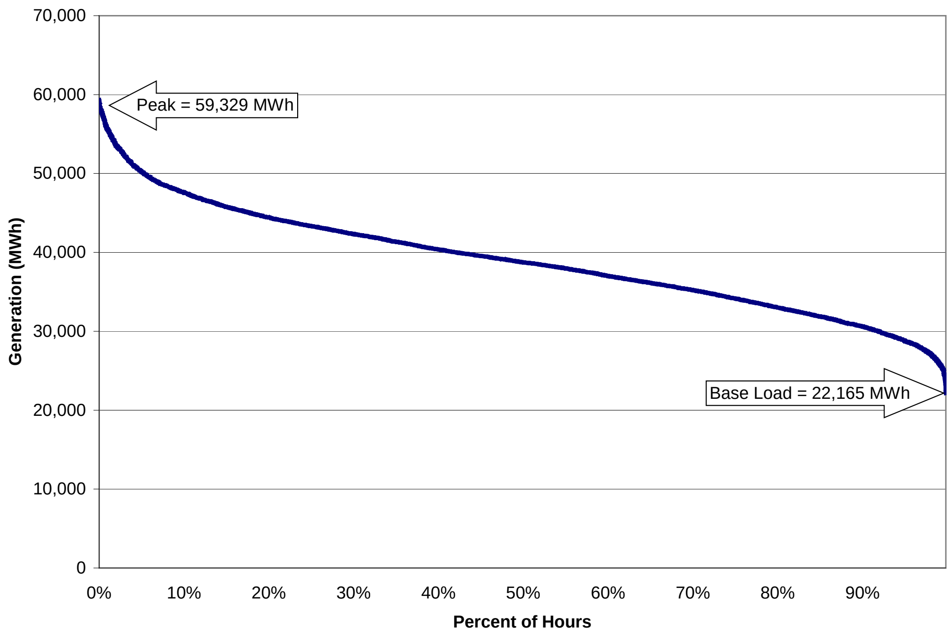
4. REVISED EMISSION FACTORS

This chapter will discuss the general nature of the generation and distribution system feeding Wisconsin and present the generation emission factors calculated by our revised emissions model using a number of scenarios. It will also present a discussion of emission savings from on-site reduction in natural gas use.

4.1 MAIN-MAPP GENERATION SYSTEM

The maximum electricity produced by MAIN and MAPP fossil fuel generators (coal, gas, oil, and diesel only) during 2000 was almost 60 GWh as shown in the load duration curve in Figure 4-1 (see the previous chapter for a discussion of load duration curves). Generation never dropped below 22 GWh during the year, thus the base load was 22 GWh.

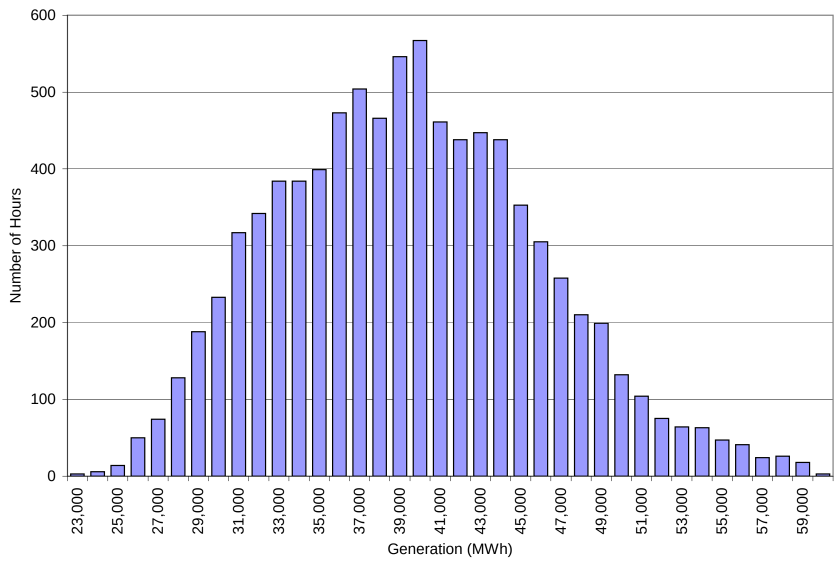
Figure 4-1. MAIN-MAPP 2000 Load Duration Curve



(Generation from fossil fuels only.)

Another way to understand the makeup of generation in the MAIN-MAPP region is to graph the distribution of generation as shown in Figure 4-2. Most hours of the year see generation of between 31,000 and 45,000 MWh. Generation exceeds 51,000 MWh for relatively few hours during the year.

Figure 4-2. Distribution of Generation in MAIN-MAPP in 2000

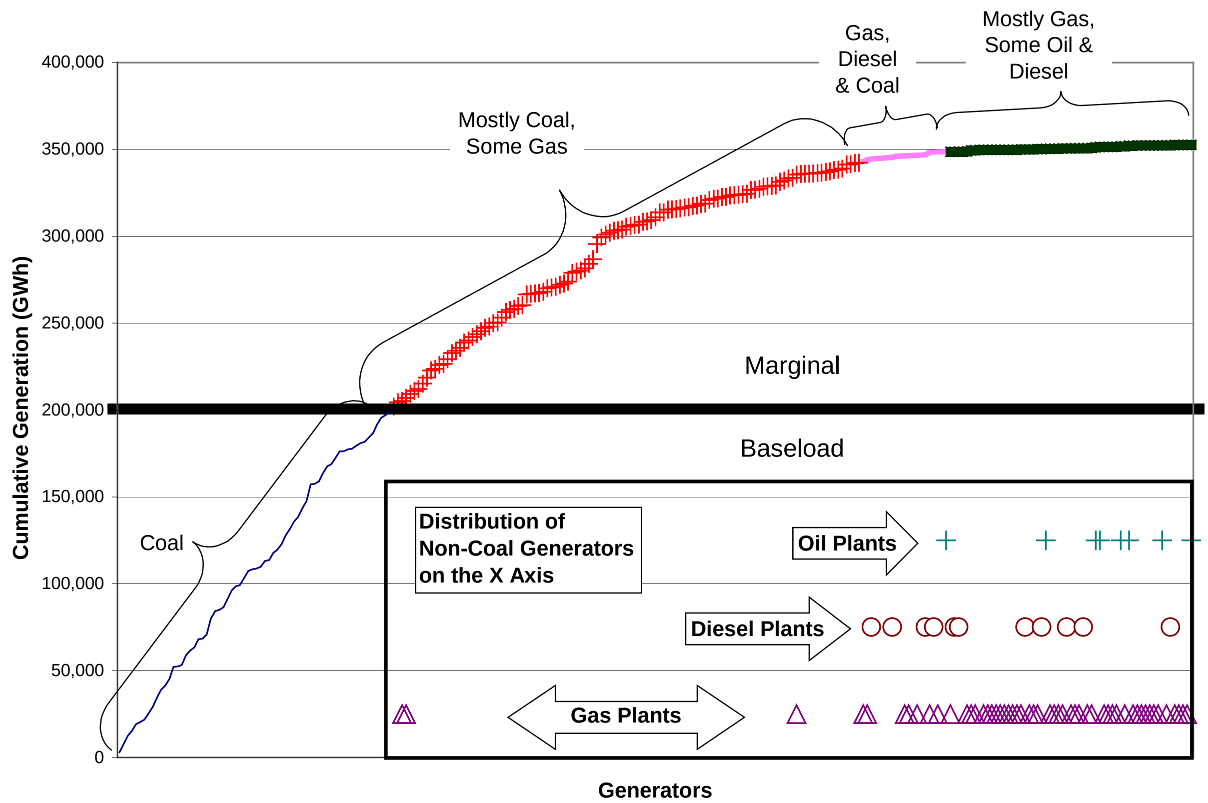


(Generation from fossil fuels only.)

The previous two graphs were created from hourly generation data, which is an input to the emissions model. To understand the fuel mix of MAIN-MAPP generators we look at an output of the model. The model examines hourly data generator by generator for fossil fueled central-station generators and identifies the baseload and marginal generators and the fuel they use. Figure 4-3 shows the distribution of generators and their cumulative generation for 2000. The generators are sorted along the X axis according to capacity factor, with capacity factor decreasing from left to right. Thus, the plants that the model assumes are baseload are graphed first followed by the marginal plants. The box in the lower right corner of the graph contains symbols indicating where along the X axis gas, diesel, and oil plants can be found. (The Y axis value for these symbols was chosen for illustration purposes only and has no meaning.)

The baseload generators were fueled only by coal (again ignoring nuclear and hydro) and together generated 200,000 GWh. Above 200,000 GWh were the marginal plants – at some point in the year they were the marginal generators. The plants generating between 200,000 and 342,000 GWh were fueled mostly by coal but some were fueled by natural gas. The first diesel plant came on line at 344,000 GWh (represented by the left-most circle in the box in the lower right corner of the graph). The first oil plant came on line at 349,000 GWh (indicated by the left-most + in the box in the graph). No coal plants were generating between 350,000 GWh and the maximum, 353,000 GWh.

Figure 4-3. Generators by Fuel Source



(Generation from fossil fuels only.)

4.2 GENERATION EMISSIONS FACTORS

This section will present yearly and seasonal generation emission factors. Generation emission factors are expressed in pounds of pollutant per MWh or GWh. These factors can be multiplied by the energy savings from Focus efficiency efforts to calculate total emissions avoided by the Focus efficiency programs. The calculations assume that the energy savings results in reduced generation at the power plant for those power plants operating at the margin during a particular time of day or season. The calculations also assume that reduced generation is perfectly correlated with reduced emissions. (This assumption may not always hold true, as will be discussed.)

This section will start by presenting yearly emissions factors, which do not take into account peak and off-peak times of day or seasonal differences in demand. The section will then present results from several scenarios that define seasons and peak and off-peak hours.

4.2.1 Summary

The emissions factors calculated by our emissions model are shown in Table 4-1. An explanation of each of the scenarios and results follows.

Table 4-1. EMISSIONS FACTORS–SUMMARY

	Pounds /MWh			Pounds /GWh	Percent of Yearly Value			
Season and Hour	**NOx**	**SOx**	**CO_2**	**Mercury**	**NOx**	**SOx**	**CO_2**	**Mercury**
Yearly	5.7	12.2	2,216	0.0489				
Broad Peak Scenario								
Winter Peak	5.9	13.9	2,027	0.0427	104%	114%	91%	87%
Winter Off-peak	5.8	14.5	2,287	0.0536	102%	119%	103%	110%
Summer Peak	4.6	9.8	1,788	0.0346	81%	80%	81%	71%
Summer Off-peak	5.4	11.1	2,233	0.0524	95%	91%	101%	107%
Narrow Peak Scenario								
Winter Peak				No winter peak hours				
Winter Off-peak	5.1	11.0	2,076	0.0461	89%	90%	94%	94%
Summer Peak	2.9	6.0	1,476	0.0181	51%	49%	67%	37%
Summer Off-peak	5.4	11.2	2,073	0.0431	95%	92%	94%	88%
Shoulder Scenario								
Shoulder Peak	5.0	10.4	2,186	0.0510	88%	85%	99%	104%
Shoulder Off-peak	7.1	16.2	2,269	0.0547	125%	133%	102%	112%
Non-shoulder Peak	4.8	11.1	1,945	0.0395	84%	91%	88%	81%
Non-shoulder Off-peak	5.9	13.5	2,260	0.0517	104%	111%	102%	106%

Scenarios:
"Broad Peak:" Summer Peak is April–September 8 am–10 pm workdays. Winter Peak is October–March 7 am–10 pm workdays.
"Narrow Peak:" Summer Peak is June–August 1 pm–4 pm workdays. All other hours are off-peak.
"Shoulder:" Shoulder is March, April, and October; peak is 7 am to 10 pm workdays.

4.2.2 Yearly Generation Emission Factors

The yearly emissions factors calculated by our emissions model are shown in Table 4-2. The "1999 Report" values are those that have been used to date by the evaluation for estimating emission reduction from Focus activities. The "2004 Report" values are the outcomes of the revised model presented in this report. Using actual hourly emissions data on plants in the distribution region supplying Wisconsin, the marginal emissions rate for NOx is 5.7 pounds/MWh, SOx is 12.2 pounds/MWh, CO_2 is 2,216 pounds/MWh, and mercury is 0.0489 pounds/GWh (see the 2003 line in Table 4-2). The NOx, SOx, and CO_2 emissions rates are of approximately the same magnitude as the values from the 1999 Focus report. (The 1999 report did not include a mercury emission factor.)

Table 4-2. YEARLY EMISSIONS FACTORS

Source	Year of Data	Type	Pounds /MWh NOx	Pounds /MWh SOx	Pounds /MWh CO_2	Pounds /GWh Mercury
1999 Report	1999	By Marginal Cost	6.4	10.8	2,400	
1999 Report	1999	By Capacity Factor	5.9	10.0	2,035	
1998 EPA	1998					0.0373
2004 Report	**2000**		**5.7**	**12.2**	**2,216**	**0.0489**

Sources:
1999 Report: *Development of Emissions Factors for Quantification of Environmental Benefits*, June 25, 2001. Focus on Energy Pilot Evaluation Report.
1998 EPA: EPA's *E-Grid 2000 Database* for MAIN and MAPP for 1998.
2004 Report: This report.

Coal produces the most emissions from the marginal generators in the yearly data (see Table 4-3), followed by natural gas. Diesel generators produce a sizeable fraction of the CO_2. Coal produces significantly more emissions per MWh than the other fuels for all but CO_2 (Table 4-4).

Table 4-3. CONTRIBUTION OF FUELS TO MARGINAL EMISSIONS–YEARLY MODEL

	Percent of Total Emissions			
Fuel	**NOx**	**SOx**	**CO_2**	**Mercury**
Coal	95.4%	98.6%	87.7%	99.0%
Pipeline Natural Gas †	2.8%	1.1%	6.2%	0.0%
Natural Gas †	0.4%	0.1%	0.6%	0.0%
Residual Oil	0.2%	0.0%	0.9%	0.2%
Diesel Oil	1.1%	0.2%	4.6%	0.9%
Total	100.0%	100.0%	100.0%	100.0%

† Pipeline Natural Gas and Natural Gas differ in the amount of hydrogen sulfide (H_2S) they contain with Pipeline Natural Gas having less.

Table 4-4. MEAN EMISSIONS RATE BY FUEL–ALL PLANTS (Not Just Marginal Plants)

	Pounds /MWh			Pounds /GWh
	NOx	**SOx**	**CO_2**	**Mercury**
Coal	5.68	11.63	2,270	0.0541
Pipeline Natural Gas	1.78	0.25	1,451	0.0000
Natural Gas	3.20	2.98	1,816	0.0000
Residual Oil	0.57	0.25	420	0.0016
Diesel Oil	2.27	1.50	906	0.0068
Total	4.22	7.51	1,889	0.0344

4.2.3 Seasonal and Peak Generation Emission Factors

We examined emissions from generators operating at the margin in four time periods:

- Winter Peak Hours
- Winter Off-peak Hours
- Summer Peak Hours
- Summer Off-peak Hours.

The results are, of course, sensitive to the definition of which months fall in winter and summer and which hours of the day fall in or out of peak. We examine emissions using three scenarios for defining peak and seasons (see Table 4-5).

Table 4-5. SEASON AND PEAK SCENARIOS

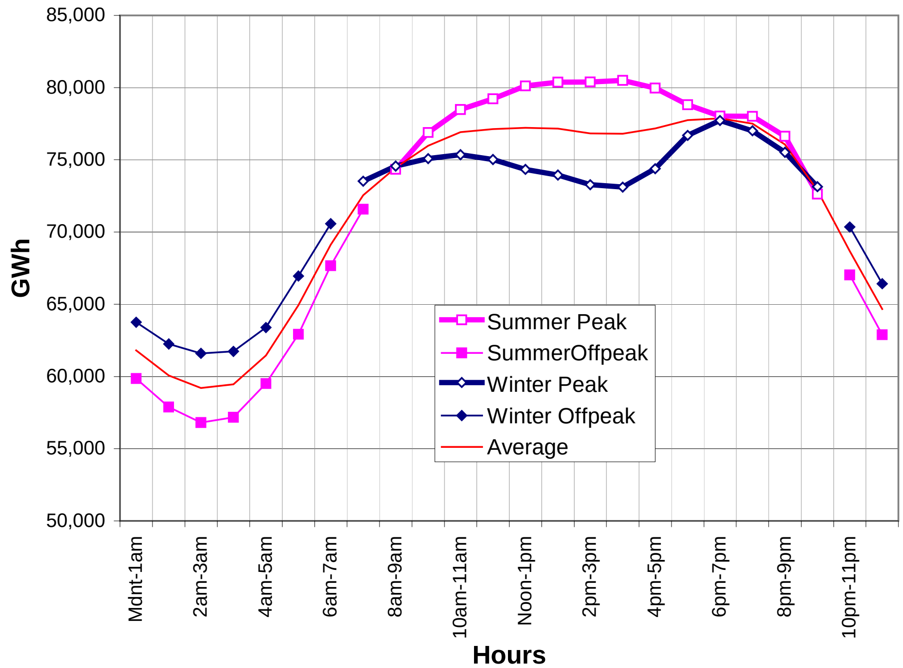
Scenario	Season	Summer Peak Hours*	Winter Peak Hours*
Broad Peak (Base Case)	April–September = Summer Months	8 am–10 pm	7 am–10 pm
Narrow Peak	June–August = Summer Months	1 pm–4 pm	None
Shoulder	March, April, October = Shoulder Months	7 am–10 pm	7 am–10 pm
Yearly	January – December	No peak hours defined	

All peak hours are for workdays only, not including weekends.

Broad Peak. The first scenario, referred to as "Broad Peak," uses a broad definition of the hours of peak. Wisconsin utilities face a fairly protracted peak in both summer and winter (see Figure 4-4). The summer peak builds through the day to a maximum in the early afternoon. The winter load curve shows a small peak around 10:00 in the morning then a small dip before reaching a higher peak around 6:00 in the evening. We examined the peak curves and visually estimated the peak hours at from 7:00 am to 10:00 pm on workdays in the winter and 8:00 am to 10:00 pm on workdays in the summer. During these hours, peak demand is within 94% of the yearly maximum demand.

In the Broad Peak scenario April through September are considered summer months.

Figure 4-4. DAILY LOAD CURVE FOR BROAD DEFINITION OF PEAK HOURS



Total energy usage in the MAIN and MAPP NERC regions by time of day in 2000.

The highest emissions rates in the broad peak scenario are during the winter off-peak hours, the lowest emissions rates are in the summer peak hours (Table 4-6). The difference between the highest and lowest rates is quite dramatic. For an explanation, we can look at the contribution to emissions by fuel (Table 4-7). In all times of year and day, coal produces the vast majority of the emissions but during peak hours natural gas plants are much more likely to be running, producing a substantial fraction of the CO_2. During off-peak hours, natural gas produces between 2.7% and 3.8% of CO_2 emissions. However during peak summer hours, natural gas produces 22% of the CO_2 emissions. Natural gas power plants are substantially cleaner than coal plants for NOx, SOx, and mercury emissions and somewhat cleaner for CO_2. As a result, the increased use of natural gas power plants during the peak hours produces lower marginal emissions factors than during the off-peak hours.

Table 4-6. EMISSIONS FACTORS–BROAD PEAK SCENARIO

	Pounds/MWh			Pounds/GWh
Season and Hour	**NOx**	**SOx**	**CO_2**	**Mercury**
Winter Peak	5.9	13.9	2,027	0.0427
Winter Off-peak	5.8	14.5	2,287	0.0536
Summer Peak	4.6	9.8	1,788	0.0346
Summer Off-peak	5.4	11.1	2,233	0.0524

Scenario: “Summer Peak” is April–September, 8 am–10 pm workdays. “Winter Peak” is October–March, 7 am–10 pm workdays.

Table 4-7. CONTRIBUTION OF FUELS TO MARGINAL EMISSIONS–BROAD PEAK

	Percent of Total Emissions			
Fuel	**NOx**	**SOx**	**CO_2**	**Mercury**
Summer Peak				
Coal	89.1%	98.1%	76.3%	98.8%
Natural Gas	7.9%	0.4%	22.0%	0.0%
Summer Off-peak				
Coal	95.8%	99.7%	93.9%	99.2%
Natural Gas	2.5%	0.3%	3.8%	0.0%
Winter Peak				
Coal	93.0%	99.5%	82.1%	98.8%
Natural Gas	4.6%	0.3%	14.6%	0.0%
Winter Off-peak				
Coal	98.2%	99.7%	96.9%	99.9%
Natural Gas	1.7%	0.3%	2.7%	0.0%

Scenario: "Summer Peak" is April–September, 8 am–10 pm workdays. "Winter Peak" is October–March, 7 am–10 pm workdays.

Narrow Peak. The second scenario, referred to as "Narrow Peak," uses a narrow definition of the hours of peak and the season. Peak is from 1 pm to 4 pm on workdays during the months of June, July, and August. All other hours are off-peak (see Figure 4-5). This is the definition specified by DOA for use in calculating peak savings from the Focus efficiency programs.[15]

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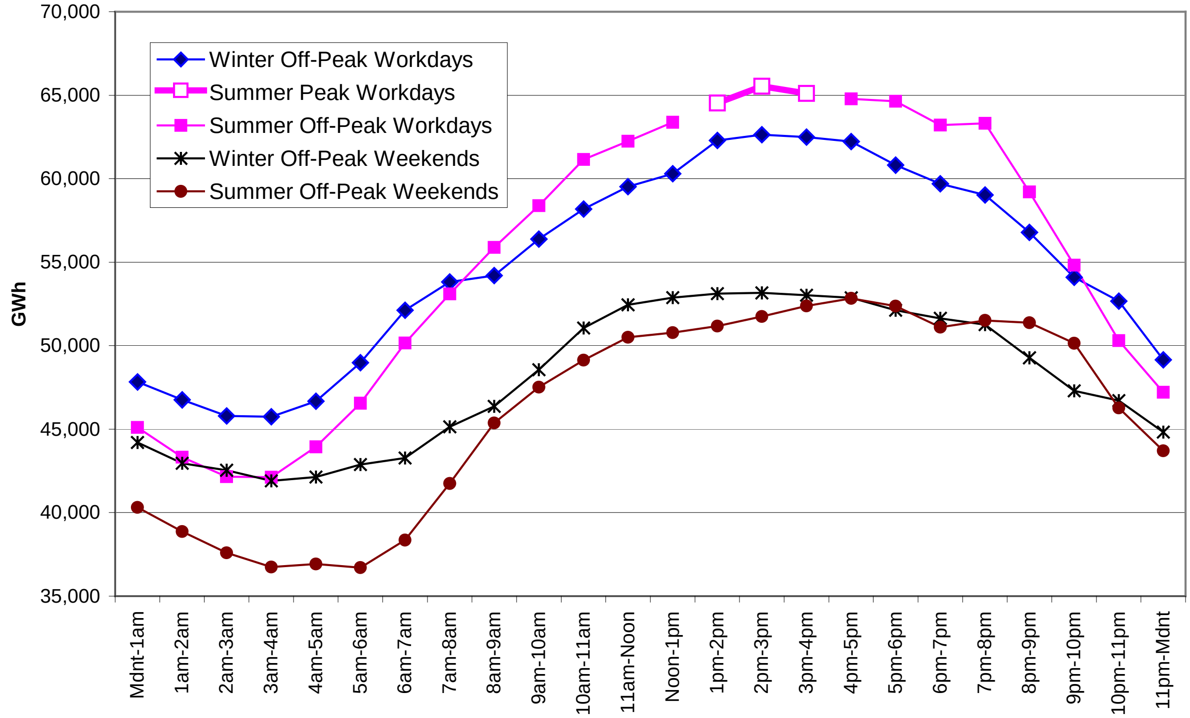
[15] Source: E-mail from Mr. Oscar Bloch, Wisconsin Division of Energy, on September 10, 2002.

Figure 4-5. Daily Load Curve for Narrow Definition of Peak Hours



Total energy usage in the MAIN and MAPP NERC regions by time of day in 2000.

The highest emissions rates in the narrow peak scenario are during the off-peak hours, the lowest emissions rates are in the summer peak hours (Table 4-8). The difference between the highest and lowest rates is even more dramatic than in the Broad Peak scenario. For an explanation, we can look at the contribution to emissions by fuel (Table 4-9). In the winter, natural gas contributes only 8% of the CO_2 emissions; most of the remainder come from coal. In the summer off-peak hours natural gas contributes 14.1% of the CO_2 emissions. However, during the summer peak hours, natural gas usage goes up substantially and it now contributes 44.9% of the CO_2 emissions. As with the Broad Peak scenario, the increased use of natural gas power plants during the peak hours produces lower marginal emissions factors than during the off-peak hours.

Table 4-8. EMISSIONS FACTORS–NARROW PEAK SCENARIO

	Pounds/MWh			Pounds/GWh
Season and Hour	**NOx**	**SOx**	**CO_2**	**Mercury**
Winter Peak	No winter peak hours			
Winter Off-peak	5.1	11.0	2,076	0.0461
Summer Peak	2.9	6.0	1,476	0.0181
Summer Off-peak	5.4	11.2	2,073	0.0431

Scenario: “Summer Peak” is June–August, 1 pm–4 pm workdays. All other hours are off-peak.

Table 4-9. CONTRIBUTION OF FUELS TO MARGINAL EMISSIONS–NARROW PEAK

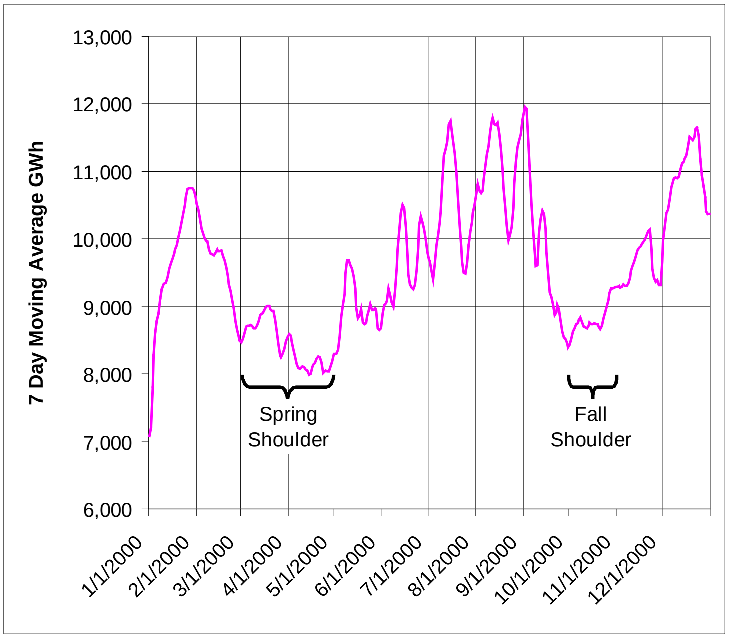
	Percent of Total Emissions			
Fuel	**NOx**	**SOx**	**CO_2**	**Mercury**
Summer Peak				
Coal	72.1%	98.2%	51.6%	96.1%
Natural Gas	20.5%	0.7%	44.9%	0.0%
Summer Off-peak				
Coal	90.5%	98.1%	82.8%	99.2%
Natural Gas	8.0%	1.6%	14.1%	0.0%
Winter Peak				
Coal	No winter peak hours			
Natural Gas				
Winter Off-peak				
Coal	93.3%	98.0%	88.2%	99.2%
Natural Gas	3.8%	1.9%	8.0%	0.0%

Scenario: "Summer Peak" is June–August, 1 pm–4 pm workdays. All other hours are off-peak.

Shoulder. Because electricity demand is typically lower in the spring and fall, the shoulder months, power plants shutdowns for planned maintenance are often scheduled for this time. The hypothesis for the third scenario, referred to as "Shoulder," is that if the plants normally used to meet peak demand are shut down for maintenance in the shoulder months and if an unexpected heat wave occurs, then less-desirable peaking plants will have to be called into service to meet demand. If those backup peaking plants emit more pollutants than the average plant (for example, if they were diesel or older coal plants) then the emission factors in the shoulder months would be higher.

To identify the shoulder months we examined a yearly load curve for all plants in the analysis (Figure 4-6). March and April in the spring and October in the fall have the lowest energy usage and were defined as the shoulder months for this scenario. We used peak hours of 7 am to 10 pm on workdays, comparable to the Broad Peak scenario.

Figure 4-6. YEARLY LOAD CURVE AND SHOULDER DEFINITION



The highest emissions rates in ***any*** scenario tested are in the Shoulder Off-peak hours—during the nighttime in March, April, and October (Table 4-10). During those hours ***only*** coal plants are running (Table 4-11), which have higher emissions than the natural gas plants that might be running if demand were higher. During the Shoulder Peak hours (daytime in March, April, and October) emission rates were not as high as the non-shoulder off-peak hours. These results do not support the hypothesis stated above if plant maintenance typically happens during the day. A more likely hypothesis is that demand is so low during the shoulder periods that base-load coal burning power plants can provide all the power needed and there is no need to go to other sources to meet demand. Also, since the utilities must keep most coal plant boilers fired at temperature so that thermal stress due to contraction does not occur, coal plants are likely used more often in shoulder periods because they are readily available.

Table 4-10. EMISSIONS FACTORS–SHOULDER SCENARIO

	Pounds/MWh			Pounds/GWh
Season and Hour	**NOx**	**SOx**	**CO_2**	**Mercury**
Shoulder Peak	5.0	10.4	2,186	0.0510
Shoulder Off-peak	7.1	16.2	2,269	0.0547
Non-shoulder Peak	4.8	11.1	1,945	0.0395
Non-shoulder Off-peak	5.9	13.5	2,260	0.0517

Scenario: “Shoulder” is March, April, and October. “Peak” is 7 am to 10 pm workdays.

Table 4-11. CONTRIBUTION OF FUELS TO MARGINAL EMISSIONS–SHOULDER

	Percent of Total Emissions			
Fuel	**NOx**	**SOx**	**CO_2**	**Mercury**
Non-shoulder Peak				
Coal	88.5%	98.0%	78.4%	98.8%
Natural Gas	8.3%	1.3%	19.5%	0.0%
Non-shoulder Off-peak				
Coal	97.3%	99.4%	93.9%	99.9%
Natural Gas	2.5%	0.6%	5.6%	0.0%
Shoulder Peak				
Coal	99.4%	99.9%	95.1%	99.8%
Natural Gas	0.2%	0.1%	3.8%	0.0%
Shoulder Off-peak				
Coal	100.0%	100.0%	100.0%	100.0%
Natural Gas	0.0%	0.0%	0.0%	0.0%

Scenario: "Shoulder" is March, April, and October. "Peak" is 7 am to 10 pm workdays.

Comparison of the Three Scenarios. The lowest emissions rates of any scenario are in the summer peak hours in the Narrow Peak scenario—or between 1 pm and 4 pm between June and August—which is DOA's definition of the peak season (Figure 4-7). The highest emissions rates are in the shoulder off-peak hours of the Shoulder scenario—or nighttime in March, April, and October. The key determinant of the emissions rates is the amount of power supplied by natural gas burning plants. Coal is the predominant fuel source in all hours and seasons (Table 4-12), but natural gas provides the bulk of the peaking power during times of high system peak. Coal produces over 90% of the CO_2 emissions in many season/hour combinations across the three scenarios, however it produces only 51.6% of the CO_2 emissions in the Narrow Peak scenario during Summer Peak hours.

Generally speaking, other fuels (not coal or natural gas and not counting non-emitting sources of power like hydro and nuclear) provide a very small portion of the power at any time of the year and have a fairly small effect on the emissions rates. The exceptions are highlighted in (Table 4-13). For example, in Narrow Peak scenario during Summer Peak hours, diesel produces 5.6% of the NOx emissions. Diesel produces 4.6% of the CO_2 emissions in the broad yearly scenario.

Figure 4-7. EMISSION RATES ACROSS THREE SCENARIOS
(Percent of Maximum Emission Rate by Substance)

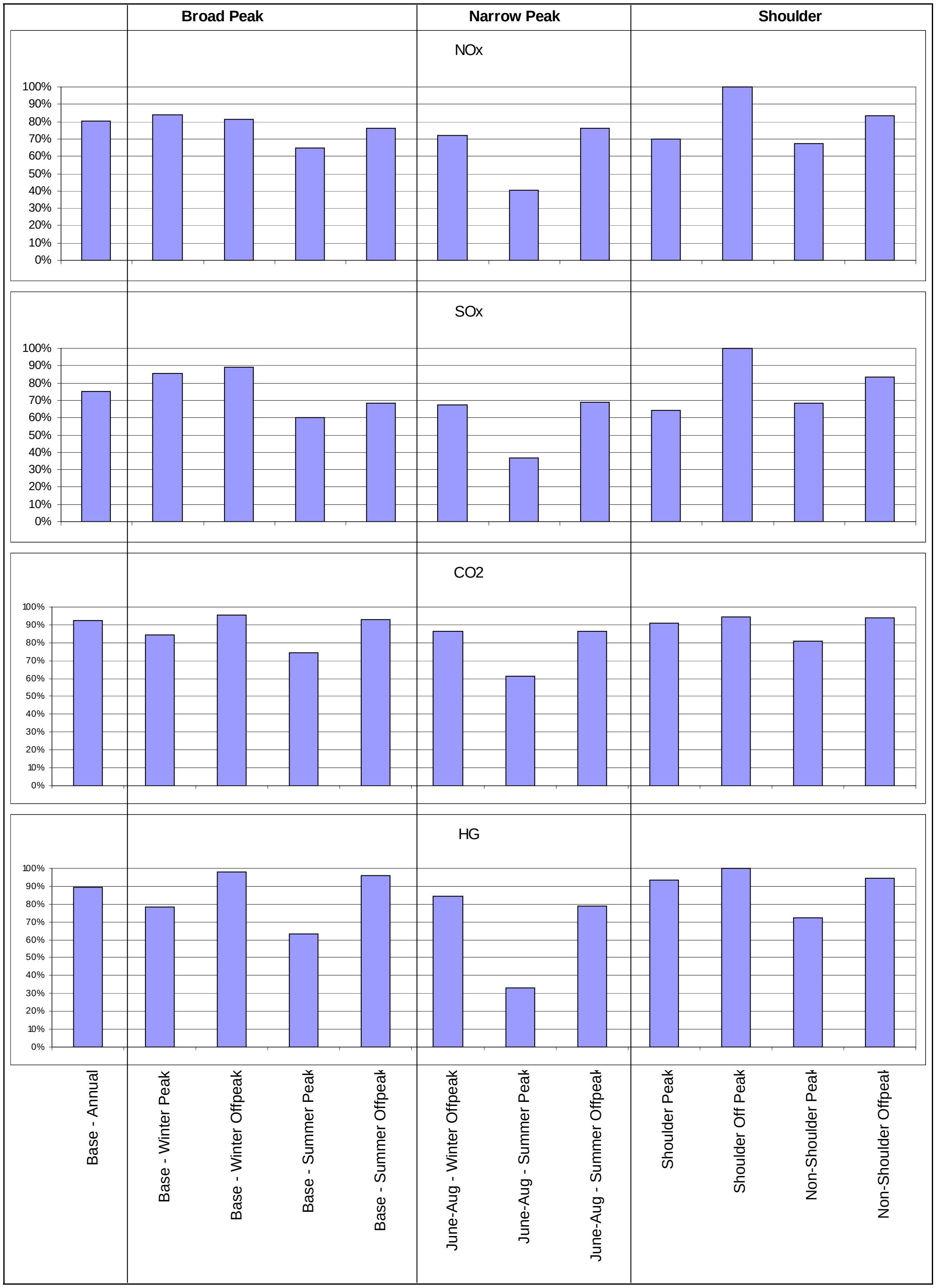


Table 4-12. COAL CONTRIBUTION TO MARGINAL CO_2 EMISSIONS BY SCENARIO

Scenario	Percent of Total Marginal CO_2 Emissions Produced by Coal-burning Power Plants: Summer or Non-shoulder Peak	Summer or Non-shoulder Off-peak	Winter or Shoulder Peak	Winter or Shoulder Off-peak
Broad Peak	76.3%	93.9%	98.8%	99.9%
Narrow Peak	51.6%	82.8%	NA	88.2%
Shoulder	78.4%	93.9%	95.1%	100.0%

Table 4-13. CONTRIBUTION TO MARGINAL EMISSIONS BY FUELS OTHER THAN COAL AND NATURAL GAS

Scenario	Fuel	NOx	SOx	CO_2	Mercury
Broad Yearly	Residual Oil	0.2%	0.0%	0.9%	0.2%
Broad Yearly	Diesel Oil	1.1%	0.2%	4.6%	0.9%
Broad Winter Peak	Residual Oil	0.2%	0.0%	0.4%	0.1%
Broad Winter Peak	Diesel Oil	2.2%	0.1%	3.0%	1.1%
Broad Winter Off-peak	Residual Oil	0.0%	0.0%	0.0%	0.0%
Broad Winter Off-peak	Diesel Oil	0.1%	0.0%	0.4%	0.1%
Broad Summer Peak	Residual Oil	0.4%	0.2%	0.3%	0.1%
Broad Summer Peak	Diesel Oil	2.6%	1.4%	1.4%	1.1%
Broad Summer Off-peak	Residual Oil	0.3%	0.0%	1.3%	0.2%
Broad Summer Off-peak	Diesel Oil	1.4%	0.0%	1.0%	0.6%
Narrow Winter Off-peak	Residual Oil	0.2%	0.0%	0.4%	0.1%
Narrow Winter Off-peak	Diesel Oil	2.7%	0.2%	3.5%	0.7%
Narrow Summer Peak	Residual Oil	1.8%	0.4%	1.7%	0.5%
Narrow Summer Peak	Diesel Oil	5.6%	0.7%	1.9%	3.3%
Narrow Summer Off-peak	Residual Oil	0.2%	0.0%	0.5%	0.1%
Narrow Summer Off-peak	Diesel Oil	1.2%	0.3%	2.6%	0.7%
Shoulder Off-peak	Residual Oil	0.0%	0.0%	0.0%	0.0%
Shoulder Off-peak	Diesel Oil	0.0%	0.0%	0.0%	0.0%
Shoulder Peak	Residual Oil	0.0%	0.0%	0.0%	0.0%
Shoulder Peak	Diesel Oil	0.4%	0.0%	1.1%	0.2%
Non-shoulder Off-peak	Residual Oil	0.0%	0.0%	0.0%	0.0%
Non-shoulder Off-peak	Diesel Oil	0.1%	0.0%	0.4%	0.1%
Non-shoulder Peak	Residual Oil	0.3%	0.1%	0.4%	0.1%
Non-shoulder Peak	Diesel Oil	2.9%	0.6%	1.7%	1.1%

Any value larger than 2% is highlighted.

4.3 NATURAL GAS ON-SITE USE EMISSIONS FACTORS

The emission factors discussed above are for emissions savings at the electric generator. Other emissions savings occur when energy efficient projects reduce the use of non-electric fuels at the participant's site. The primary site-based fuel (burned at the participant's site rather than at the power generation plant) saved under the Focus program is natural gas.[16] Combustion of natural gas produces a variety of pollutants including CO_2, NOx, N_2O, SOx, PM10, VOC, and CO. With the exception of CO_2, these pollutants are emitted in fairly small quantities.

According to the EPA's Technology Transfer Network Clearinghouse for Inventories & Emission Factors, the emission factor for CO_2 is 120,000 pounds of CO_2 per 1 million standard cubic feet of gas, which converts to 11.76 pounds of CO_2 per therm (Table 4-14).[17] According to the Clearinghouse, this emission factor is based on approximately 100% conversion of fuel carbon to CO_2. However, "in properly tuned boilers, nearly all of the fuel carbon (99.9%) in natural gas is converted to CO_2 during the combustion process. This conversion is relatively independent of boiler or combustor type."[18]

The Clearinghouse provides a single emission rate for SOx and mercury, as it does for CO_2. (Both the SOx and mercury values are quite small, particularly compared to coal, and as a result are often ignored.) Natural gas coming out of the ground has very little sulfur in it. However, since natural gas has little smell, sulfur-containing odorants are added to give it the smell of rotten eggs to increase the chances that leaks will not go undetected. The Clearinghouse estimate for sulfur assumes all the sulfur added to gas is emitted.

The Clearinghouse provides a range of estimates for NOx that depend on the size and configuration of the boiler. NOx emissions are particularly sensitive to the size, design, and operating conditions of the boiler.

The upper bound emission rate shown in the following table is for large wall-fired boilers (greater than 100 MMBtu/hour) that use no control techniques to reduce NOx. It is the highest emission rate in the Clearinghouse document we used. The lower bound is for a small boiler (less than 100 MMBtu/hour) with low NOx burners and flue gas recirculation. It is the lowest rate in the document we used. The mid-range emission rate was chosen somewhat arbitrarily—it is the upper bound of the small boilers, the lower bound of the large boilers, and just a little bit higher than the emissions rate for residential furnaces. See Table 4-15 for the emission factors for all the configurations presented by the Clearinghouse.

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[16] The authorizing legislation for Focus defines "Energy conservation program" as "a program for reducing the demand for natural gas or electricity or improving the efficiency of its use during any period." http://www.legis.state.wi.us/1999/data/acts/99Act9.pdf

[17] (120,000 Pounds/106 scf)/(1,020 MMBtu/106 scf)/(10 MMBtu/Therm) = 11.76 Pounds/Therm Source: *Compilation of Air Pollutant Emission Factors*, AP-42, Fifth Edition, Volume I: Stationary Point and Area Sources. EPA Technology Transfer Network Clearinghouse for Inventories & Emission Factors. http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s04.pdf.

[18] Ibid.

Table 4-14. NATURAL GAS ON-SITE USE EMISSION FACTORS

Substance	Pounds Per Therm
CO_2	11.76
SOx	0.0000588
Mercury	0.00000002549
NOx Lower Bound	0.003137
NOx Mid-range	0.009804
NOx Upper Bound	0.027451

Sources:
(1) Compilation of Air Pollutant Emission Factors, AP-42, Fifth Edition, Volume I: Stationary Point and Area.
(2) EPA Technology Transfer Network Clearinghouse for Inventories and Emission Factors.

Table 4-15. NATURAL GAS ON-SITE USE NOX EMISSION FACTORS

Combustor Type	Pounds Per Therm
Large Wall-fired Boilers (>100 MMBtu/Hour Heat Input)	
Uncontrolled (Pre-NSPS)	0.027451
Uncontrolled (Post-NSPS)	0.018627
Controlled–Low NOx burners	0.013725
Controlled–Flue gas recirculation	0.009804
Small Boilers (<100 MMBtu/Hour Heat Input)	
Uncontrolled	0.009804
Controlled–Low NOx burners	0.004902
Controlled–Low NOx burners/Flue gas recirculation	0.003137
Tangential-fired Boilers (All Sizes)	
Uncontrolled	0.016667
Controlled–Flue gas recirculation	0.007451
Residential Furnaces (<0.3 MMBtu/Hour Heat Input)	
Uncontrolled	0.009216

Sources:
(1) Compilation of Air Pollutant Emission Factors, AP-42, Fifth Edition, Volume I: Stationary Point and Area.
(2) EPA Technology Transfer Network Clearinghouse for Inventories & Emission Factors.

NSPS = New Source Performance Standard as defined in 40 CFR 60 Subparts D and Db. Post-NSPS units are boilers with greater than 250 MMBtu/hr of heat input that commenced construction modification, or reconstruction after August 17, 1971, and units with heat input capacities between 100 and 250 MMBtu/hr that commenced construction modification, or reconstruction after June 19, 1984.

5. FOCUS EMISSION BENEFITS QUANTIFIED

Using the emission factors developed by the revised model, energy savings created by Focus efficiency programs, and an estimate of the market for the avoided emissions, we can estimate emission savings in pounds and dollars from Focus efficiency programs.

The process involves the following steps:

- Calculate emission factors in pounds/MWh (Chapter 4)
- Separate Focus savings into the season and time-of-use bins (Percentage of MWh in each bin by measure type) (the next section of this chapter)
- Define potential value of pollution allowances in U.S. dollars/pound (the second section of this chapter)
- Calculate total pounds of emission savings and the total dollar value of those savings (the final section of this chapter).

5.1 ENERGY SAVINGS BY SEASON AND PEAK

In its first two years of operation, the Focus on Energy program has documented significant energy savings. Focus has saved almost 400 million kilowatt-hours of electricity and almost 18 million therms of natural gas (as of December 31, 2003 based on evaluation-verified gross), reducing consumers' annual utility bills by almost $30 million dollars. Three sets of energy impact numbers are calculated for Focus efficiency programs: program-reported gross, evaluation verified gross, and evaluation calculated net, defined as follows:

Gross Reported Savings	Energy savings as reported by the program administrator, unverified by an independent evaluation.
Verified Gross Savings	Energy savings verified by an independent evaluation based on reviews of the number and types of implemented improvements, and the engineering calculations used to estimate the energy saved.
Verified Net Savings	Energy savings that can confidently be attributed to Focus efforts. Evaluators make adjustments for participants who were not influenced by Focus.

Although the situation is still the subject of debate, it appears likely that regimes for valuing and trading emissions credits created by energy efficiency and renewable programs will calculate credits based on **net** savings. In the discussion that follows, we present emissions results based on reported gross as the calculation of net energy savings is more properly the subject of other reports. However, readers should be aware that the emissions reductions presented as examples in this report could be reduced by as much as ½ if net savings were used.

The program tracking databases for the Focus efficiency programs do not document seasonal variations in energy savings and it is not clear whether they are using a consistent approach to defining the hours and type of peak savings. As a result, in order to estimate seasonal and peak emissions the evaluation team undertook an exercise to estimate the seasonal and hourly savings distribution for measures installed through Focus.

We divided the percentage of annual savings for each measure being installed through Focus into four bins—winter peak, winter off-peak, summer peak, and summer off-peak—using the Broad Peak definitions. For example, a residential central air conditioner is primarily operated during summer peak period (64.9% of operation), with some operation during summer off-peak period and no operation during either the winter peak or winter off-peak periods (Table 5-1). While a residential furnace is not operated in either summer peak or summer off-peak periods but is primarily operated during the winter off-peak period (52.1% of operation), with the remaining 47.9% of operation occurring during the winter peak period.

Where we could not establish a reasonable estimate of season and peak use for a measure, or the measure description was not clear, we assigned a distribution that matched the distribution of all the other measures combined, which therefore would not affect the overall distribution.

We made the technology-bin assignments based on work done by the New Jersey Clean Energy Collaborative and reported in *Protocols to Measure Resource Savings*[19] and on evaluation internal judgment. The peak and season definitions in the New Jersey Protocols most closely resemble the Broad Peak scenario[20] so we used emission factors from that scenario in our calculations. To make the bin assignments correspond to the Narrow or Shoulder scenarios would require significant adjustments to the Protocols' estimates, an optional future task we discuss in Chapter 6.

Table 6-1 below provides an example of load distributions assigned for two residential measures.

Table 5-1. LOAD DISTRIBUTION EXAMPLES

Measure Type	Summer Peak	Summer Off-peak	Winter Peak	Winter Off-peak
Residential Central Air Conditioner	64.9%	35.1%	0.00%	0.00%
Residential Furnace	0.00%	0.00%	47.90%	52.10%

Once each measure's savings is divided into the bins, we can calculate the total savings in the bins.

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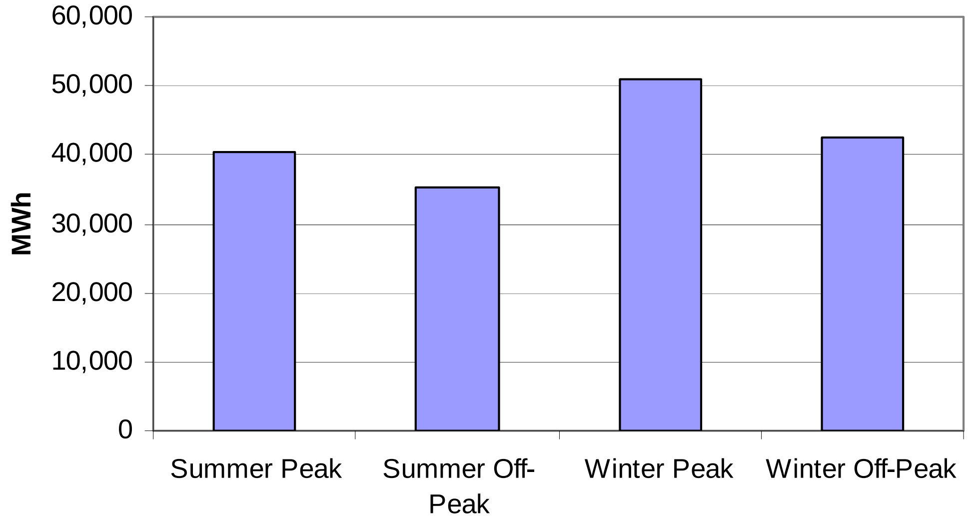
[19] July 9, 2001. http://www.njcleanenergy.com/media/2001_07_09_BPU-Filing/a2_protocol_to_measure.pdf. The New Jersey Protocols state that they use "industry-accepted algorithms" and that the standard values used in those algorithms for most commercial and industrial measures are "supported by end use metering for key parameters for a sample of facilities and circuits, based on the metered data from the GPUE Shared Savings Program. These commercial and industrial (C&I) standard values are based on five years of data for most measures and two years of data for lighting. Some electric and gas input values were derived from a review of literature from various industry organizations, equipment manufacturers, and suppliers."

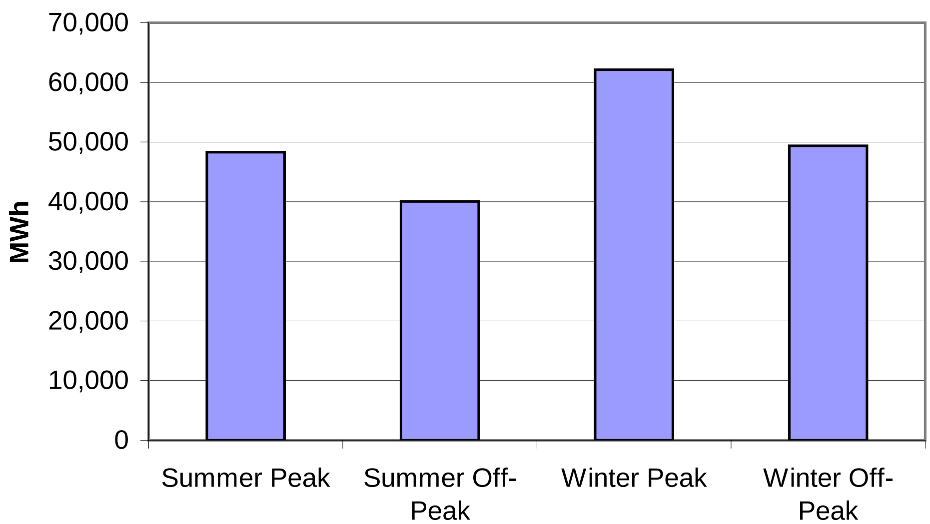
[20] The New Jersey Protocols define *summer* as May–September, whereas the Broad Peak scenario uses April–September. The Protocols define *Peak* as 8 am to 8 pm, whereas the Broad Peak scenario uses 8 am to 10 pm in the summer and 7 am to 10 pm in the winter.

Figure 5-1. DISTRIBUTION OF RESIDENTIAL ENERGY IMPACTS ACROSS TIME PERIODS



Based on energy impacts data through September 2003 and the Broad Peak emission factors.

Figure 5-2. DISTRIBUTION OF BUSINESS PROGRAMS ENERGY IMPACTS ACROSS TIME PERIODS



Based on energy impacts data through September 2003 and the Broad Peak emission factors.

5.2 POTENTIAL VALUE OF FOCUS-GENERATED POLLUTION CREDITS

Assuming that stricter air pollution controls are desirable and will come into being, and that the form of controls will be cap-and-trade systems, the State of Wisconsin may be able to motivate the creation of a valuable asset by creating pollution credits from energy efficiency and the generation of renewable energy from its Focus on Energy program (See Chapter 7 for a fuller discussion of this issue). To estimate the potential value of that asset, we need to estimate the value of tradable emission credits.[21]

A national market exists for emission allowances for SOx and a regional one exists for NOx in the northeast (not in Wisconsin). The SOx market began in 1995 as a result of the Clean Air Act Amendments of 1990. It serves a national cap and trade program developed with a goal of reducing emissions from power generation by 50 percent. The NOx market serves the Ozone Transport Commission (OTC) NOx Budget Program, a cap and trade program developed in the northeastern United States. It also serves the NOx SIP Call[22] from EPA and the Federal NOx Budget Trading Program. Trading of NOx allowances under OTC began in 1999 to reduce NOx emissions during the summer months when smog forms. [Kinner and Clean Air Markets Update, Issue 3] Under emission allowance programs, utilities are allocated allowances for emitting SOx and NOx, one allowance per short ton of NOx or SOx. The reduction in emissions sought determined the number of allowances allocated. At the end of a year, each utility must have enough allowances to cover the amount of NOx and SOx they emitted during the year. They must either reduce their level of emissions or purchase allowances from other utilities to meet their goals. Many allowances are moved internally to individual utilities as they balance the efficiency of their stable of generators. However, enough allowances are traded on the open market between utilities to provide a valid estimate of the market value of allowances.[23]

In the United States, there is no cap and trade regulation or regional agreement for CO_2 as there is for NOx and SOx. However, a market does exist for CO_2 emissions, as created under the Chicago Climate Exchange (CCX). CCX is a self-regulatory, voluntary pilot program designed to develop a trading program for greenhouse gasses. Its members have signed legally binding agreements to reduce their emissions of greenhouse gases by four percent below the average of their 1998-2001 baseline by 2006, the last year of the pilot program (Chicago Climate Exchange).

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[21] In this report we will use “emission credits” to refer to the potentially tradable units of measure created by energy efficiency and renewable energy programs and will use “emission allowances” to refer to the pollution allowances distributed to and traded by those who produce emissions, typically utilities and large industries. Both are denominated in pounds of substance per year and both could, in theory at least, be traded in the same market.

[22] The NOx SIP Call required 22 states and the District of Columbia to submit State Implementation Plans providing NOx emission reductions to mitigate ozone transport in the eastern United States.

[23] In 2001, approximately 41 percent of the SOx allowances were traded between companies according to Clean Air Markets Update #1 September 2001.

There is currently no market for mercury emission allowances in the United States. The Energy Information Administration (EIA) modeled the potential value of mercury allowances to analyze the potential costs and effects of legislation for establishing a national cap and trade system for NOx, SOx, and mercury (EIA 2001). EIA's estimated values for mercury in 2010 varied from $12,500 per pound to $34,500 per pound, depending on the scenario analyzed.

Table 5-2 shows current and projected prices for tradable allowances. For 2004, the table shows current market prices in the markets discussed above for SOx, NOx, and CO_2. For 2010 we used prices from PA Consulting Group's "Multi-pollutant Optimization Model," which assumes enactment of the Bush Administration's "Clear Skies" proposal. For a lower bound on mercury prices, the projections assume EPA's estimated price of $16,000/ton.

We used the lower bound of the 2010 prices later in this chapter when we report the dollar values of the avoided emissions.

Table 5-2. EMISSION ALLOWANCE PRICES

Type of Emission	Historical Price (3/2003-2/2004 Average)	Current Price (2/2004)	Projected Price (2010)
SOx	$194/ton	$269/ton	$295-$348/ton
NOx	$3,581/ton	$2,400/ton	$1,573-$1,643/ton
CO_2	N/A	$0.95/ton	$5-$10/ton
Mercury	N/A	N/A	$16,000-$118,053/lb

Note: tons are U.S. short tons and CO_2 is not carbon but tons of CO_2. CO_2 is often denominated in metric tons of carbon but we use short tons of CO_2 to maintain consistency with the other calculations.
Source: Current prices for NOx and SOx: Cantor Environmental Brokerage Market Price Indices. Current price for CO_2: Chicago Climate Exchange. Projected Prices: PA Consulting Group M-POM model.

When we use the annual emissions rates to calculate estimate the potential value of avoided emissions, CO_2 represents 44% of the total value of avoided emissions for each MWh avoided. NOx represents 36%, SOx 14%, and mercury 6%. Thus the calculations results discussed in the remainder of this paper will be more susceptible to the vary more with changes in assumed prices for CO_2 and NOx values than the other substances.

Details on the calculations of the potential value of allowances are presented in Appendix B.

5.3 TOTAL EMISSIONS AVOIDED BY SEASON AND PEAK

Once the savings are segregated into the season/peak bins, calculating pounds of emissions avoided by bin and the total value of that savings is a math exercise. The following formula defines the math behind the calculation of the value of the emissions avoided by bin.

Figure 5-3. FORMULA FOR CALCULATING AMOUNT OF EMISSIONS AVOIDED BY BIN

$$\underbrace{\underbrace{\underbrace{\sum_{c}^{n}\underbrace{(MWh_c \bullet \%Bin_b)}_{\text{MWh/Bin by measure}}}_{\text{Total MWh/Bin}} \bullet EMF_{ab}}_{\text{Total Pounds/Bin}} \bullet \$/Pound_a}_{\text{\$/Bin}} = \text{Value of Emissions Avoided by Emission Type and Bin}$$

a	Substance (NOx, SOx, CO_2, Hg)
b	Bin for season/peak combination (Summer Peak, Summer Off-peak, Winter Peak, Winter Off-peak)
c	Individual measure type installed through Focus
n	Total number of individual measure types installed through Focus
MWh	Energy saved by projects completed for this measure type (MWh)
%Bin	Distribution of savings in the season/peak bins (%)
EMF	Emission factor for the season/peak bin (pounds/MWh)

The results of performing this calculation for the Business and Residential Programs is shown in the following table. Total value of emissions savings for Business Programs is $2,885,877 and for Residential Programs is $1,812,062. The largest single source of savings for both Residential and Business Programs is for winter peak CO_2 and the smallest is summer off-peak SOx.

We examined the value of emissions avoided by subprogram within the Residential and Business Programs offerings and found little difference in the relative emissions impact of the various programs when impacts were denominated in dollars and standardized to the program size.

Table 5-3. POUNDS AND VALUE OF EMISSIONS AVOIDED BY PEAK/SEASON AND PROGRAM

	Business Programs				Residential Programs			
Period	**SOx**	**NOx**	**CO_2***	**Hg**	**SOx**	**NOx**	**CO_2***	**Hg**
				Pounds				
Summer Off-peak	444,544	216,265	89,429,423	2.1	300,946	146,406	60,541,736	1.4
Summer Peak	473,349	222,184	86,362,026	1.7	311,951	146,426	56,915,134	1.1
Winter Off-peak	715,544	286,218	112,858,634	2.6	597,750	239,100	94,279,589	2.2
Winter Peak	863,768	366,635	125,961,032	2.7	681,608	289,316	99,397,104	2.1
On-site Natural Gas	757	126,146	151,313,733					
Total	**2,497,206**	**1,091,302**	**414,611,115**	**9.1**	**1,892,255**	**821,248**	**311,133,562**	**6.8**
				Dollars				
Summer Off-peak	65,570	170,092	223,574	33,577	44,390	115,149	151,354	22,731
Summer Peak	69,819	174,748	215,905	26,739	46,013	115,164	142,288	17,622
Winter Off-peak	105,543	225,110	282,147	42,321	88,168	188,052	235,699	35,354
Winter Peak	127,406	288,359	314,903	42,455	100,537	227,547	248,493	33,502
On-site Natural Gas	112	99,214	378,284					
Total	**$368,449**	**$957,523**	**$1,414,812**	**$145,092**	**$279,108**	**$645,912**	**$777,834**	**$109,209**
Program Total	**$2,885,877**				**$1,812,062**			
Focus Total	**$4,697,939**							

Based on program-to-date energy impacts data through September 30, 2003, and the Broad Peak emission factors. Using credit prices of $0.1475/pound for SOx, $0.7865/pound for NOx, and $0.0025/pound for CO_2 and $16,000/pound for mercury.

* The pounds of CO_2 in this table include generation savings and on-site savings from natural gas. [Reference Table 1-3 in Executive Summary.]

5.4 VALUE OF EMISSIONS AVOIDED BY TECHNOLOGY OR MEASURE TYPE

By estimating the peak and season impacts for each technology or measure, we can then estimate the value of the yearly and lifetime avoided emissions for a given amount of energy saved. By converting savings to a common unit—the market value of avoided emissions—we can then compare the emissions impact of individual measures. Table 5-4 shows the relative emissions impacts of measures included in Residential Programs. The largest savings on an annual basis were for an ECM furnace, heating system fuel switching, showerheads for electric water heaters, and bathroom faucet aerators for electric water heaters. Attic, sidewall, and sill box insulation had the largest value of lifetime savings.

Table 5-4 also shows the distribution of savings (or energy use) across the peak and season periods (using the Broad Peak definition).

Table 5-4. RELATIVE EMISSION BENEFITS OF RESIDENTIAL PROGRAMS

Measure Type	Summer Peak	Summer Off-Peak	Winter Peak	Winter Off-Peak	Annual Avoided Emissions Dollars per MWh	Lifetime Avoided Emissions Dollars per MWh	Installed Units per MWh
Attic Insulation	47.91%	26.21%	12.41%	13.47%	$11.39	$227.80	3.0
Sidewall Insulation	47.91%	26.21%	12.41%	13.47%	$11.39	$227.80	0.9
Sill Box Insulation	47.91%	26.21%	12.41%	13.47%	$11.39	$227.80	9.1
ECM Furnace	0.00%	0.00%	47.90%	52.10%	$12.88	$193.14	1.0
Furnace Fuel Switch	3.00%	3.00%	45.00%	49.00%	$12.78	$191.63	0.1
Showerheads - Electric	10.00%	40.00%	10.00%	40.00%	$12.49	$187.28	2.0
Faucet Aerators - Bath - Electric	10.00%	40.00%	10.00%	40.00%	$12.49	$187.28	5.3
Dishwashers	19.80%	21.80%	27.80%	30.60%	$12.20	$183.01	11.1
Refrigerator	20.90%	21.70%	28.00%	29.40%	$12.16	$182.47	15.2
Clothes Washer (WESH)	24.50%	12.80%	41.70%	21.00%	$12.02	$180.33	13.2
Clothes Washers (ESP)	24.50%	12.80%	41.70%	21.00%	$12.02	$180.33	3.8
Water Heater - Fuel Switch	30.00%	20.00%	30.00%	20.00%	$11.87	$178.12	0.3
Faucet Aerators - Kitchen - Electric	40.00%	10.00%	40.00%	10.00%	$11.57	$173.54	5.3
Air Conditioner - 12 SEER	64.90%	35.10%	0.00%	0.00%	$10.87	$162.98	4.0
Air Conditioner - 13 SEER	64.90%	35.10%	0.00%	0.00%	$10.87	$162.98	2.9
Air Conditioner - 14 SEER	64.90%	35.10%	0.00%	0.00%	$10.87	$162.98	2.3
Air Conditioner - 15 SEER	64.90%	35.10%	0.00%	0.00%	$10.87	$162.98	2.0
Ceiling Fan	64.90%	35.10%	0.00%	0.00%	$10.87	$162.98	5.7
Dehumidifier	64.90%	35.10%	0.00%	0.00%	$10.87	$162.98	20.0
Room AC	65.10%	34.90%	0.00%	0.00%	$10.86	$162.92	30.3
Lighting Fixtures - Indoor	22.00%	15.00%	37.00%	26.00%	$12.12	$84.84	9.6
Lighting Fixtures - Instant	22.00%	15.00%	37.00%	26.00%	$12.12	$84.84	9.6
Lighting Fixtures - Outdoor	22.00%	15.00%	37.00%	26.00%	$12.12	$84.84	9.6
Lighting Fixtures - Torchiere	22.00%	15.00%	37.00%	26.00%	$12.12	$84.84	2.9
CFL	22.00%	15.00%	37.00%	26.00%	$12.12	$84.84	15.2
CFL (installed in multi-family facility)	22.00%	15.00%	37.00%	26.00%	$12.12	$84.84	5.8
High Pressure Sodium Lighting	22.00%	15.00%	37.00%	26.00%	$12.12	$84.84	5.8
Freezer Turn-In	20.90%	21.70%	28.00%	29.40%	$12.16	$60.82	0.9
Refrigerator Turn-In	20.90%	21.70%	28.00%	29.40%	$12.16	$60.82	0.9
Room AC Turn-In	65.10%	34.90%	0.00%	0.00%	$10.86	$54.30	1.8

Based on energy impacts data through July 2003 and the Broad Peak emission factors. The table is sorted by lifetime avoided emissions. The top four measures based on yearly avoided emissions are highlighted.

Source: New Jersey Clean Energy Collaborative for some percentages, PA Consulting Group analysis for all other values

Table 5-5 shows the relative emissions impacts of measures included in Business Programs. The largest savings on an annual basis were for reducing boiler pressure at $12.93/MWh, followed by several measures at $12.79. Custom HVAC and Custom Lighting projects had the largest value of lifetime savings.

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Table 5-5. RELATIVE EMISSION BENEFITS OF BUSINESS PROGRAMS
(Allocation of Energy Impacts by Season and Peak)

Description	Summer Peak	Summer Off-peak	Winter Peak	Winter Off-peak	Annual Avoided Emission Dollars per MWh	Lifetime Avoided Emission Dollars per MWh
II–Custom Lighting	26%	16%	36%	22%	$11.99	$240
Install HVLS Fans	45%	39%	7%	9%	$11.40	$228
Free Cooling for Printing Press Chiller System	45%	39%	7%	9%	$11.40	$228
Variable Speed Drive on new Titan Air HVAC unit.	22%	10%	47%	21%	$12.08	$193
Install VFD on Oxidation Ditch	22%	10%	47%	21%	$12.08	$193
Variable Speed Drive on Vacuum Pump	22%	10%	47%	21%	$12.08	$193
Boiler Pumping Reduction	0%	50%	0%	50%	$12.79	$192
Motor Upgrade	26%	16%	36%	23%	$12.12	$182
Variable Speed Drives	22%	10%	47%	21%	$12.08	$181
Cooler Door Heater Control	25%	25%	25%	25%	$12.03	$180
Plate Heat Exchanger	25%	25%	25%	25%	$12.03	$180
T-8 Lamps & Electronic Ballasts	26%	16%	36%	22%	$11.99	$180
II - 4L-4' T8 Electronic Ballast	26%	16%	36%	22%	$11.99	$180
MH to T8 Lighting Retrofit	26%	16%	36%	22%	$11.99	$180
T8 Fluorescent Upgrade	26%	16%	36%	22%	$11.99	$180
Metal Halide Reduction	26%	16%	36%	22%	$11.99	$156
Occupancy Sensors	26%	16%	36%	22%	$11.99	$156
Fluorescent Conversion	26%	16%	36%	22%	$11.99	$156
Warehouse Lighting	26%	16%	36%	22%	$11.99	$156
Energy Management System	0%	50%	0%	50%	$12.79	$128
Install Vending Miser	0%	50%	0%	50%	$12.79	$128
Upgrade Air Compressor	25%	16%	36%	23%	$12.02	$120
Compressed Air System	25%	16%	36%	23%	$12.02	$120
Lighting Reduction	26%	16%	36%	22%	$11.99	$120
Lighting Schedule-Controls	26%	16%	36%	22%	$11.99	$120
Replace Electric Water Heaters with Gas	25%	25%	25%	25%	$12.03	$108
Lighting Controls	26%	16%	36%	22%	$11.99	$108
LED Traffic Lights	12%	21%	24%	43%	$12.48	$87
II - Compaq Florescent Lamps	26%	16%	36%	22%	$11.99	$60
II - Commercial Washer B2	30%	20%	30%	20%	$11.87	$59
Reduce Boiler Pressure	0%	0%	42%	58%	$12.93	*
Building lighting upgrade	26%	16%	36%	22%	$11.99	
Custom Refrigeration Measure	25%	25%	25%	25%	$12.03	
Add thermostatic controls to unit heater fans	45%	39%	7%	9%	$11.40	
Custom Refrigeration Measure	25%	25%	25%	25%	$12.03	
Compressed Air Feasibility Study	25%	16%	36%	23%	$12.02	
Custom Compressed Air Measure	25%	16%	36%	23%	$12.02	
High Service Pumping	22%	10%	47%	21%	$12.08	
HVAC Feasibility Study	0%	50%	0%	50%	$12.79	

Based on energy impacts data through July 2003 and the Broad Peak emission factors. The table is sorted by lifetime avoided emissions. The top measures based on yearly avoided emissions are highlighted.

* The lifetime was not clear from the information we had for the measures at the bottom of the table.

This analysis indicates that there is a fairly significant range in emissions impacts across technologies for both Residential and Business Programs. Annual avoided emissions savings for residential technologies vary from $10.86/MWh to $12.88/MWh. Business technologies vary from $11.40/MWh to $12.93/MWh. As a result, it would be possible to modify program designs to optimize a program's impact on emissions. The key conclusion from the season and peak analysis is that the highest emissions occur in off-peak hours and the lowest in on-peak hours. This is consistent with the general observation that coal provides most of Wisconsin's base load generation (ignoring nuclear and hydro since they emit no NOx, SOx, etc.) and natural gas plants are used more often as peaking plants. These results imply that any effort to maximize a program's emissions impacts will have to be balanced with the program's effort to reduce peak demand.[24]

[24] See Erickson et al. 2004 ACEEE paper listed in references at the end of this report for a discussion of comparing the value of emissions reduction to the value of demand reduction.

6. POTENTIAL ENHANCEMENTS TO EMISSIONS MODEL OR ANALYSIS

There are a number of ways the emissions model could be used to provide more information on the potential impact of the Wisconsin Focus on Energy Programs, and there are other data collection and analysis tasks that could improve the usefulness of the results. This chapter will outline some of the most promising avenues.

6.1 ENHANCED MAPPING OF IMPACTS INTO PEAK AND SEASON BINS

The results presented in Chapter 5 came from a relatively modest effort to map program-installed measures into peak and season bins (winter peak, winter off-peak, summer peak, summer off-peak). This can provide a rough guide to program designers for identifying some technologies that offer relatively more emissions reduction impacts. Several avenues could be pursued to improve the season and peak mapping, which would provide more concrete information for program designers, as follows.

Program Tracking: Currently the Focus program tracking databases record peak demand savings but do not track information on the seasonal characteristics of energy use. In addition, it is not clear whether they are using a consistent approach to defining the hours and type of peak savings. Program and evaluation staff could work together to explore options for improving the tracking of peak demand and adding tracking of information that could be used to estimate seasonal energy use. For some technologies, information about the hardware involved will be insufficient to provide a clear picture of seasonal and peak use. For example, it is reasonable to predict an average usage patterns for residential CFLs but probably not for some industrial process-related measures. As a result, data collected from Focus field staff could be crucial in accurately defining peak and seasonal use.

Literature Review: For this report we made the technology-bin assignments based on work done by the New Jersey Clean Energy Collaborative and reported in *Protocols to Measure Resource Savings*[25] and on evaluation internal expert judgment. The technologies included in the Protocols did not cover all measures implemented under Focus and the fit between Protocol measures and Focus measures, when there was one, was not always as perfect as one might hope. It seems likely that others have created documents like the Protocols. Additional effort to find those documents and use them to fine-tune the rules of thumb used in this analysis would improve the mapping of Focus measures into peak and season bins.

Expert Input: A logical extension to the literature review would be to interview experts to get their advice on typical usage patterns, particularly for measures that are not well matched to measures in the Protocols or other such documents.

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[25] New Jersey Clean Energy Collaborative. 2001. Protocols to Measure Resource Savings. July 9, 2001. http://www.njcleanenergy.com/media/2001_07_09_BPU-Filing/a2_protocol_to_measure.pdf.

Rules of Thumb for Scenario Analysis: The peak and season definitions in the New Jersey Protocols most closely resemble the Broad Peak scenario[26] so we used emission factors from that scenario in our calculations. To make the bin assignments correspond to the Narrow or Shoulder scenarios would require significant adjustments to the Protocols' estimates. One approach we could take would be to develop some simple rules for translating the bin percentages from one definition of peak and season to another. For example, we could establish rules to scale up or down the usage percentages according to the percentage of the year included in the definition.

Modeling and Data Mining: If the literature review does not enable us to create significantly improved maps of impacts into peak and season bins, we could undertake a modeling and data mining exercise to develop our own estimates. This would likely entail identifying and analyzing existing load curve data and perhaps running load modeling programs such as DOE-2. This effort could even extend to collecting original data through on-site metering and monitoring but it seems unlikely that such a level of effort is justified in the current circumstances.

6.2 EXPANDED FINANCIAL IMPACTS ANALYSIS

This report presents a conundrum: Designing programs to target peak demand will be diametrically opposed to targeting them to maximize emissions reductions. To fairly compare the two goals it would help to express the benefits of both approaches in dollars. Chapter 5 discusses an approach to converting emissions benefits to dollars. By expanding that analysis to include the dollar benefits of peak demand reduction, we could provide more concrete information for comparing tradeoffs between the two approaches.[27]

6.3 ALTERNATIVE SCENARIOS

We examined three scenarios in this report, varying the definition of seasons and peak hours. There are unlimited possibilities for defining other scenarios that could be tested but three seem to hold particular promise:

Peak and Season: We examined three definitions of peak in this report, labeled "Broad," "Narrow," and "Shoulder." The Narrow peak hours (1 pm to 4 pm June to August) were designed to represent the coincident maximum system peak for the purposes of demand savings estimation. The Broad peak hours were much broader—8 am to 10 pm from April to September. Examining emissions from some middle range, say traditional working hours or perhaps 10 am to 5 pm, might provide emissions rates that would be more relevant for some kinds of program results.

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[26] The Protocols define *summer* as May–September, whereas the Broad Peak scenario uses April–September. The Protocols define *Peak* as 8 am to 8 pm, whereas the Broad Peak scenario uses 8 am to 10 pm in the summer and 7 am to 10 pm in the winter.

[27] See Erickson et al. 2004 ACEEE paper listed in references at the end of this report for a discussion of comparing the value of emissions reduction to the value of demand reduction.

Wisconsin Generators: This report calculated emissions factors assuming all generators in the MAIN and MAPP NERC regions might provide power to Wisconsin. While there are strong reasons for making this assumption, it would be educational to know what the emission factors would be if only generators sited in Wisconsin were included in the analysis. We could include only Wisconsin generators or also include those that are within a certain distance of Wisconsin's borders.

Wisconsin Off-peak Generators: During peak periods it is more likely that power is being imported into Wisconsin than exported. However, this may not be the case during off-peak hours. As a result, it may be informative to run a scenario that includes non-Wisconsin generators during peak hours but only Wisconsin generators during times of particularly low demand.

6.4 USE 2001 AND 2002 DATA

When this revised model was initially designed and tested the only data available was from 2000. Data from 2001 and 2002 are now available. Running the model with data from one or both of these years would provide information on the stability of the emissions rates over time and, possibly, on trends in the emissions rates.

6.5 OTHER ENHANCEMENTS TO THE MODEL

The Pilot model used either a calculated marginal cost or capacity factor to determine which plants operate on the margin. The current model uses only capacity factor but could be refined to also calculate and use marginal cost. The capacity factor approach accurately models how the systems were actually used during the year. However, if there was something out of the ordinary about the year that would reduce the model's ability to accurately predict the future. The marginal cost approach would provide one method for overcoming that potential shortcoming. The model would dispatch plants using the logic that we assume actual dispatchers would use—running the cheapest generators before the more expensive generators, irrespective of their historical capacity factor. Thus the marginal cost approach would calculate emission factors under ideal circumstances, not under the perhaps messy circumstances actually encountered.

The model used for the results presented in Chapter 4 of necessity uses a number of assumptions. We chose conservative approaches to making these assumptions and believe they are well supported. However, we could test the robustness of the model by testing alternative approaches for some assumptions. For example, energy usage was missing in a not insignificant number of cases in the hourly data when it appears from other data that energy was generated. We estimated usage using other data but to enhance the model we could calculate it in a number of different ways and test the sensitivity of the model to the different approaches. As another example, alternative approaches to calculating capacity factor could be tested.

6.6 DO ENERGY SAVINGS YIELD INCREASED EXPORTS INSTEAD OF REDUCED GENERATION IN WISCONSIN?

It is possible that reductions in demand within Wisconsin produce increased exports of power to neighboring states instead of decreased generation and thus emissions from Wisconsin-based power plants. Such a situation would produce economic benefits for Wisconsin but it might mean that the benefits of the emission reductions estimated by our model would not be enjoyed by Wisconsin residents. This problem is not unique to the model presented in this report—it is a problem that faces most attempts to calculated avoided generation emissions from energy efficiency projects.

Three routes hold potential promise for addressing this issue. First, we could modify the model to divide the emission factors into in-state and out-of-state factors, based on the location of the power plants identified as the marginal producers. Second, we could attempt to model imports and exports during various seasons and peak combinations then use the model outputs to calibrate the emissions model. Such an approach would be complex and costly and, given the competition for evaluation resources, it is probably not reasonable to expect that this route should be pursued. The third route would be to interview MAIN and MAPP dispatch staff and others knowledgeable about the market for power in Wisconsin and attempt to answer the following questions:

1. Can we identify with reasonable confidence non-Wisconsin power plants whose power is likely to be consumed in Wisconsin under a given set of circumstances?
2. Alternatively, is the power market either too complex or too opaque to be able to answer question #1?
3. If the answer to #1 is "Yes", then which non-Wisconsin power plants are more likely to provide power used in Wisconsin at the margin?
4. Under what situations or in what conditions would energy savings from Focus programs result in reduced power plant generation and thus emission savings in Wisconsin?

6.7 MAPPING

If we pursue finding answers to the previous questions, it may be helpful in understanding the answers to create maps showing various inputs and outputs of the revised model. The EPA data used in the model contains the latitude and longitude of each plant. We could use that data and model outputs to create maps to help examine implications of the model. For example, we could map assumed or calculated power flows into and out of the state by generator under various conditions to illustrate where emission reductions are likely to be felt. We could create a map showing where different fuels are used in generators around the state to illustrate where emissions reductions might be felt under certain conditions. We could map capacity factors to illustrate which plants are more likely to be operating under various scenarios. We could map emission rates to highlight plants or regions that are more likely to be of interest if targeting at a region is examined. We could map energy demand around the state in various seasons and times of the day to make it clearer how demand and energy flow through the state. (The EPA data contains only plants that emit the target pollutants and thus does not contain such plants as nuclear, hydro, and wind. We could attach data on such plants to the model's data, if appropriate, to provide a more complete picture of demand.)

7. EMISSIONS CREDITS, TRADING, AND OWNERSHIP

Energy savings created by Focus efforts can produce a variety of benefits including financial savings to participants, improved reliability, and health benefits that come from reduced emissions. The magnitude and nature of the potential emissions benefits are affected by a variety of factors discussed in this report. One final factor, and potentially the most important factor, is the regulation of emissions.

Given the ability to sell power outside the region and given the national cap-and-trade system for SOx and regional caps on NOx, a generator has several choices when faced with a reduction in demand created by an energy efficiency program. They could continue operating as before but sell more power to others. In that case, the only way reduced emissions would be felt in Wisconsin is if the sold power replaces power generated up-wind of Wisconsin so that there might be a reduction of pollutants floating into Wisconsin.

Generators faced with reduced demand could dial down their pollution control systems to maintain a constant level of emissions while improving operating efficiency. In that case no emissions benefits would be felt by anyone but the utility would experience lower costs, which theoretically could get reflected in lower rates.

Finally, generators faced with reduced demand could reduce production. That would result in reductions in NOx, CO_2, and mercury. Given the national caps on SOx, reduced production would free up emissions allowances which the generator could use in a variety of ways. They could trade them, bank them for future use, or use them to cover emissions from one of their other generators. In some situations, this could lead to reduced emissions in Wisconsin, but it is not a guarantee.

If Focus on Energy or individual companies on their own are responsible for the reduction in demand, then they may wish to try to claim ownership of the pollution allowances. This chapter will discuss the prospects for stricter air pollution controls and issues of the ownership of pollution allowances that programs like Focus create.

Stricter controls on four air pollutants are on the horizon with pressures coming at the state, national, and international levels. The likely means of achieving these stricter controls is through cap-and-trade systems, in which total emissions are capped, credits for pollution reductions are created, and companies trade these in a way that minimizes total compliance costs. The Wisconsin Focus on Energy Program is reducing air pollution from power plants by reducing the sales of electricity and conserving natural gas. There is the potential to create and take ownership of the credits for this reduced pollution.

The evaluation team conducted a brief assessment of this opportunity, asking two questions:

- What are the prospects for stricter cap-and-trade controls on various air pollutants?
- What are the key issues in the creation and ownership of such credits?

The sections below deal with each of the questions.

7.1 PROSPECTS FOR STRICTER AIR POLLUTION CONTROLS

As a result of federal action, Wisconsin is likely to see stricter controls on electric utility emissions of four pollutants in the coming years: sulfur oxides (SOx), nitrogen oxides (NOx), mercury, and greenhouse gases (GHG). In addition, the U.S. EPA is in the process of tightening the standards for particulate matter (soot) and ozone (smog), with NOx being a precursor of ozone. Increased energy efficiency helps on all of these air pollution fronts.

SOx is already subject to a national cap-and-trade system in which Wisconsin utilities and other large emitters have been allocated a certain number of pollution allowances. NOx emissions from electric utilities are subject to a traditional regulatory approach, i.e., an emission rate limit measured in pounds of NOx per million BTU of fuel. NOx emissions are also regulated on a regional basis to help control ozone. EPA is currently in the process of developing regulations for mercury. Currently, only GHGs are under no reduction mandate. However, all four of these pollutants could become subject to cap-and-trade systems in the future, hence the potential for creation of pollution credits.

President Bush's "Clear Skies" proposal would impose a tighter cap on SOx and establish new caps on NOx and mercury. He has signaled that "Clear Skies" is his top environmental legislative priority.[28] He has proposed controversial changes to the New Source Review (NSR) program with utilities generally supportive of the changes, and environmentalists and many states opposed. Even if opponents' fears materialize (i.e., that NSR changes could lead to emission increases from some plants), the "Clear Skies" program would enlarge the market for air pollution credits. The circumstances surrounding each pollutant are discussed in the sections below.

7.1.1 Sulfur Dioxide (SO_2)

SO_2 emissions are a primary cause of acid rain. Nationally, SO_2 emissions from utilities, private power generators, and some large industries are subject to a cap-and trade system. Total emissions are about 11 million short tons per years and will decline to just under 9 million tons later in this decade as a bank of credits is used up. Both the Bush Administration and many in Congress support future reductions in SO_2 emissions as part of multi-pollutant legislation. The Bush Administration's "Clear Skies" proposal would limit SO_2 emissions to 4.5 million tons by 2010 and 3 million tons beginning in 2018. Competing proposals in Congress would limit emissions to 2.25 million tons on tighter timeframes. Given significant bipartisan support, legislation that imposes substantially tighter SO_2 controls could pass in the next two years.

7.1.2 Nitrogen Oxides (NOx)

NOx emissions are precursors of both acid rain and ozone. Nationally, electric utility plants must meet standards of approximately 0.4 to 0.9 pounds per MMBtu, depending on the type of boiler. Plant emissions can also be averaged. Recently, EPA gave notice that it will restrict

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[28] "Clear Skies is White House's Top Legislative Priority," *Air Daily*, January 10, 2003, p. 1. A summary of the proposal can be found at http://www.whitehouse.gov/infocus/environment/.

NOx emissions during the summer months of May through September in 19 northeastern states (excluding Wisconsin) to an average of 0.15 pounds per MMBtu beginning in 2004.

Total NOx emissions from the power sector are currently about 5 million short tons annually from the power sector (2000 data). However, the Clear Skies proposal also would impose a cap-and-trade system for NOx with limits of 2.1 million tons by 2008, and 1.7 million tons by 2018. Competing proposals in Congress in would limit emissions to as little as 1.5 million tons on tighter timeframes. As in the case of SO_2, legislation that imposes much tighter NOx controls could pass in the next two years.

7.1.3 Mercury

Concerns over toxicity and possible mutagenic effects of exposure to mercury have led to efforts to control of mercury emissions from various sources including coal-fired power plants (currently unregulated and totaling about 48 short tons nationally). The Clear Skies proposal also would impose a cap-and-trade system for mercury that would limit emissions to 26 tons in 2010, and 15 tons in 2018. Competing proposals in Congress would limit emissions to 5 to 16 tons on tighter timeframes. In early 2004, EPA proposed new air rules for reducing emissions of sulfur dioxide (SO2), nitrogen oxides (NOx), and mercury. EPA subsequently released proposed rule language for a model cap-and-trade approach that will reduce mercury emissions by 70 percent when fully implemented.[29]

7.1.4 Greenhouse Gases (GHG)

The principal man-made greenhouse gas (GHG) is carbon dioxide (CO_2), produced primarily by combustion of fossil fuels. Other GHGs include methane and some other trace gases. Most scientists believe that the accumulation of GHGs in the atmosphere is leading to global climate change that will have costly impacts on human society and ecosystems. The policy landscape surrounding global climate change and GHGs is very complex and warrants a detailed discussion.

At the international level, many industrialized nations are preparing to implement the Kyoto Protocol to the Framework Convention on Climate Change. Under this agreement, they will collectively reduce their GHG emissions to roughly 5% below their 1990 levels by 2010. The Clinton Administration signed the Kyoto Protocol in 1997, but the Bush Administration reversed the U.S. position and has set its own course on climate change. The EU, Japan, and other nations are preparing to move forward. Recent announcements by Russian officials indicating that they may not ratify the Protocol have thrown some doubt on whether it will ever be formally brought into force. The Kyoto Protocol has a GHG credit trading provision that allows trading between industrialized nations and credit-generating projects in developing nations. Many industrialized nations are also developing national cap-and-trade systems as the mechanism for compliance with the Protocol, and the EU has instituted a cap-and-trade scheme for CO_2 as well.

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[29] http://www.epa.gov/air/mercuryrule/

At the national level, President Bush has set a goal for the country of reducing the greenhouse gas intensity of the U.S. economy (GHGs per unit of output) by 18% over the next 10 years. While reduced GHG intensity can slow the growth in emissions, the Administration's goal ties emissions to economic performance and does not assure that any specific level of reduction is achieved. Total GHG emissions are likely to grow substantially between now and 2012 even if the goal is met. He has proposed voluntary programs and tax incentives to reach that goal. President Bush directed the Department of Energy to reform and improve its national GHG registry (the "1605(b) registry") to ensure its usefulness in a future cap-and-trade program.

At the state level, Wisconsin is one of many states with a GHG emission reduction registry in place or under development (covering GHG and other pollutants as well). Several states have cap-and-trade systems for CO_2 emissions from electric utilities (e.g., Massachusetts) or require new plants to offset their CO_2 emissions (e.g., Oregon). Many states are implementing or developing broad action plans to reduce GHG emissions including Wisconsin, Iowa, Illinois, Pennsylvania, and California. The New England states are developing a joint action plan, and New York is expected to announce its state plan soon. Over 130 U.S. cities and counties (including Madison, Milwaukee, and Dane County) are implementing GHG emission reduction plans as well.[30]

As part of various voluntary programs, some prominent companies are setting GHG emission reduction targets and engaging in GHG credit trading to help achieve the target (e.g., Entergy, DuPont, BP Amoco). In January 2003, the Chicago Climate Exchange launched a voluntary cap-and-trade system involving over a dozen companies including two electric utilities.[31]

Given all of this activity, several informal markets with different rules and institutional frameworks for GHG credit trading have emerged with buyers, sellers, and brokers.[32] Paradoxically, the United States has withdrawn from the Kyoto Protocol and no federal regulations on GHG emissions exist, yet many key actors in the climate arena are taking steps that reflect the expectation that a GHG cap-and-trade system is likely to come, its timing and shape being the principal questions. Many US companies with operations in the European Union or those owned in whole or in part by corporations headquartered in the EU will be drawn into these trading programs.

7.1.5 Energy Efficiency Set-asides

In the absence of the creation of an explicit set of credits for energy efficiency projects, all the air pollution credits tend to be allocated to existing emitters, thus excluding the energy

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[30] For a summary of state activity, see http://yosemite.epa.gov/oar/globalwarming.nsf/content/ActionsStateActionPlans.html. For a summary of local government activity, see www.iclei.org/us/ccp/.

[31] See http://www.chicagoclimatex.com.

[32] See "The Emerging International Greenhouse Gas Market," prepared for the Pew Center on Global Climate Change March 2002 (www.pewclimate.org/projects/trading.cfm).

efficiency programs from participation in the credit market. Therefore, an energy efficiency set-aside provision in new state or national legislation is desirable. Wisconsin has established a precedent for such a set-aside in 1999 Act 9. This legislation created a set aside for NOx emissions but it became a moot issue when Wisconsin was exempted from EPA rules that required 22 states to submit State Implementation Plans for reducing NOx emissions to mitigate ozone transport (the NOx SIP Call). While of no legal impact, this precedent should be kept in mind in future policy design.

7.2 CREATING AND QUANTIFYING EMISSIONS CREDITS

Experience to date with the national cap-and-trade system for SO_2 has focused on direct quantification and creation of pollution allowances.[33] EPA assigns utilities and other polluters an amount of allowances and continuous emission monitors record the amount of each substance emitted. If a utility takes various direct steps (e.g., scrubbing coal plants or fuel switching), it may have a surplus of assigned allowances over actual emissions. Energy efficiency programs hold the promise of creating ***indirect*** pollution credits in that consumers take steps downstream from the power plant to reduce overall power production. Reasonably accurate measurement of such indirect pollution reductions raises a number of issues: Markets for such indirect credits are likely to insist that the following questions or issues are resolved or carefully documented before a credit can become marketable:

- *Baseline:* What is the proper pre-existing quantity of emissions from which to measure to the reduction? Can the reduction in power demand be attributed to the energy efficiency program?
- *Additionality:* Was the reduction in power demand and/or pollution above and beyond any regulatory or other legal requirements? Was it above and beyond what would have happened in the absence of intervention by the energy efficiency program? Credit markets may insist that emission credits are calculated based on program-induced energy savings net of free riders.
- *Leakage:* Do the energy efficiency programs lead to any emissions increasing elsewhere? In addition, do the energy efficiency programs in one region merely result in an increase in electricity exports to neighboring regions, with no real change in the emissions of the local power plants?
- *Monitoring and Verification:* Do the reductions remain constant? How long do they last?

[33] As we discussed above, in this report we will use “emission credits” to refer to the potentially tradable units of measure created by energy efficiency and renewable energy programs and will use “emission allowances” to refer to the pollution allowances distributed to and traded by those who produce emissions, typically utilities and large industries. Both are denominated in pounds of substance per year and both could, in theory at least, be traded in the same market.

7.3 OWNERSHIP OF EMISSIONS CREDITS

Any creation of a pollution credit must take place in the context of a resolution of the ownership issue. A natural tension exists here between the entity that creates the indirect emission reduction and the utilities that are the ultimate source of the direct emissions. Each may want the benefit of the asset. The program participants may want the credit for they (typically) invested their own resources in reducing their use of grid-supplied electricity. Focus may want to claim the credits as it provided the impetus for the action that reduced electricity use (assuming a net analysis of results is used to calculate the credits). The utility may claim the credit since their plants are in most cases the location of the actual emissions reduction. Finally, if the utilities end up owning the credits, ratepayers who fund Focus may want to see the credit value reflected in reduced electricity rates or increased funding of energy efficiency rather than in increased profits.

Ownership of emissions credits created by generation from renewable sources is also not necessarily clear. In many cases, utility interconnection agreements specify that ownership of any environmental attributes are the property of the utility.[34] Such requirements may become much more common given FERC's recent decision on ownership of tradable renewable credits.[35] In other cases, renewable energy generators sell the bundled attributes to aggregators.

The existing Clear Air Act establishing the national cap-and-trade system for SO_2 allocates nearly all the pollution allowances to the electric utilities. (EPA sells a small percentage in a public auction but the proceeds still go to the utilities.) Nevertheless, the Clean Air Act is explicit in stating that the pollution allowances are ***not*** a property right.[36] This provision exists to ensure that the federal government can further tighten SO_2 emissions without creating a "taking" of property. However, this language may also prove useful if a state were to argue for ownership of an indirect pollution credit.

Regardless of how current law is interpreted on the issue of ownership, future laws can be shaped to protect the interests of entities that create indirect emission reductions. Thus, Wisconsin could join with other states in raising this issue in the coming debate in Congress over the Clear Skies proposal and its stricter controls on SO_2, NOx, and mercury. Although legislation on mandatory controls on emissions is unlikely to pass soon, there are fora that shape the informal market for credits. The Bush Administration is revising the national GHG registry. The regulations on who can report what kinds of emission reductions will have an impact on who owns and sells emissions credits in the future. Wisconsin could shape this debate as well. Needless to say, fungibility—the ability to sell the credits—is also critical.

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[34] Adam Serchuk, Serchuk Associates, personal communication, December 31, 2003.

[35] See http://www.ferc.gov/whats-new/comm-meet/100103/E-1.pdf

[36] The relevant language reads: "An allowance [i.e., SO credit] allocated under this title is a limited authorization to emit sulfur dioxide in accordance with the provisions of this title. Such allowance does not constitute a property right." See Sec. 403(f) of the Clean Air Act Amendments of 1990, Pub. L. No. 101-549, 104 Stat. 2399 (1990) (codified as amended in scattered sections of 42 U.S.C., 29 U.S.C.).

7.4 RESOURCES NEEDED TO QUANTIFY EMISSIONS CREDITS

The potential value to be gained in pursuing ownership of pollution credits must be weighed against the resources or costs needed in the pursuit. An analysis of the resources is beyond the scope of this report but a few observations can be made. Wisconsin already conducts extensive air emissions inventories and is evaluating the impacts of Focus programs. In addition, the State of Wisconsin has created a Voluntary Emission Reduction Registry covering a variety of air pollutants.[37] The incremental costs of tying these together to pursue ownership of pollution credits would appear to be small. Wisconsin would also need to help shape credit ownership policy at the national level, working in conjunction with other states with similar goals.

7.5 CONCLUDING THOUGHTS ON EMISSIONS CREDITS

There is an additional benefit to beginning now to carefully quantify indirect emission reductions. As multi-pollutant legislation moves forward at the federal level, Congress will need to make decisions on how to allocate the credits initially. This posed a difficult equity issue in 1990 in the creation of the SO_2 cap-and-trade system, and the same equity issue will loom even larger when three or more pollutants are considered for stricter controls.

The 1990 legislative history shows that Congress did a fairly good job at recognizing the efforts of those states and utilities that had already made efforts to reduce SO_2 emissions, i.e., Congress required smaller cuts from the “early adopters.” Congress will likely do the same under new multi-pollutant legislation: states and utilities that can demonstrate that they took action early to reduce SOx, NOx, mercury, and/or GHG emissions will probably receive initial allocations of pollution credits that reflect those efforts. Wisconsin benefited from this equity judgment in 1990 and could benefit again in the coming years if it carefully documents the results of Focus and other relevant programs.

If Wisconsin wishes to pursue creation and ownership of air pollution credits, it should initiate the process of addressing the known issues proactively. The State should also start building a network of other states and federal agencies, as well as NGOs, utilities, and other businesses, with the ultimate aim of securing the potential benefits of using energy efficiency as an environmental compliance mechanism.

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[37] http://www.dnr.state.wi.us/org/aw/air/registry/index.html.

APPENDIX A: DETAILS ON MERCURY EMISSIONS FACTOR CALCULATIONS

The hourly plant data from the *EPA Electronic Data Reporting for the Acid Rain Program* is the foundation for the revised emissions model presented in this report. It reports hourly emissions data for all electric utilities regulated by EPA for acid rain emissions, particularly SOx and NOx.[38] Emission of mercury is not included in the EPA Acid Rain data set therefore we collected and analyzed supplementary information to estimate the rate of mercury emission. We established a methodology that used the hourly Acid Rain data to calculate hourly mercury emissions by plant so that mercury could be analyzed alongside the other substances in the emissions model. This appendix will explain how we established the plant-level hourly mercury emissions values.

The primary factors that influence the emission of mercury include:

- Concentration of mercury in the Fuel[39]
- Preparation of the coal before firing
- Heat rate at which the fuel was burned
- Pollution control technologies installed on the unit
- Boiler type
- Chemical composition of the mercury emitted.[40]

The following mass balance equation takes these factors into consideration when calculating the amount of mercury emitted per unit of energy produced:[41] Slight modifications allowed us to apply it to the Acid Rain data to model seasonal and time of day emissions.

Hg Emission Rate	=	[Hg Fuel content	x	(Heat rate /Load)]	x	Boiler, Control Configuration
Lbs/MWh		Lbs/1012 Btu		Btu/MWh		EMF*

[38] It includes facilities with units that generate 25 MW or more, and that participate in the Acid Rain Program.

[39] While mercury is found in nearly all types of fuel, it is most highly concentrated in coal. Different types and origins of coal vary significantly in mercury content.

[40] The chemical composition of the mercury (speciation) is also important in evaluation of the impact of the mercury released. Mercury released in the elemental form compared to an oxidized form will have differing impacts on the environment and different remediation approaches will be used. This equation does not address the complexities of speciation and is instead a simple mass balance calculation.

[41] This equation is a variation on the SOx emission rate equation from the PA Consulting Report for Focus on Energy I Pilot Study, *Development of Emissions Factors for Quantification of Environmental Benefits*.

* EMF = Emissions Modification Factor.

This appendix will discuss each variable used in this equation and the process and methods used to calculate the mercury emission rate for the MAIN and MAPP region.

A.1 MERCURY CONTENT OF FUEL

Mercury is found as a trace element throughout the earth's crust, and consequently in the fuels comprised of earthen material, like coal and other fossil fuels. Fuels vary in their concentration of mercury based on their origin and on their type. To use the mass balance equation cited above, the first task is to determine how much mercury is in the fuel. The mercury content of fuel is expressed in pounds of mercury per unit of energy in the fuel (lbs Hg/10^{12} BTU).

A.1.1 Type, Origin, and Quantity of Coal

Coal generally has the highest concentration of mercury compared to other fuels, and is also the most commonly combusted fuel in plants in the MAIN and MAPP regions. Most of the coal purchased and consumed in MAIN and MAPP in 2000 was bituminous (or subbituminous). It originated from eleven states (see Table A-2) and the largest proportion came from Wyoming.

Detailed information on fuel type and origin was not available within the Acid Rain Data set used for the emissions model. Only generic fuel types (coal, gas, oil) were reported. Since mercury content is dependent upon both the coal type and its origin, the information had to be found elsewhere. The gap in the data was filled by linking two sources of data from the Energy Information Administration (EIA), a division of the U.S. Department of Energy and the Federal Energy Regulatory Commission (FERC).

The EIA form 423 data contains annual records of fuel purchased by utilities that generate 50 MW or more of power. (It is identical to the FERC form 423.[42]) This data provides information on the origin of the purchased coal by state and county but it does not classify each power plant by its NERC region.

To match each plant to a NERC region we used EIA form 906 data,[43] which reports fuel consumption and generation of all utilities by NERC region. EIA 423 and 906 both use the same 4-digit plant code, which served to link the two data sets. We identified 79 fossil fired plants of 50 MW or more from EIA 423 as belonging in the MAIN and MAPP regions.

Table A-1 summarizes the differences in these EIA 423 and 906.

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[42] The data set used for this analysis was taken from the EIA website, and contained the same plant codes as the FERC data set.

[43] EIA 906 is based on EIA form 759 and is often referred to as EIA 759. They are the same dataset.

Table A-1. DIFFERENCES IN AVAILABLE DATA

FERC 423 (EIA 423)	EIA 906 (or EIA 759) for Utilities (Also available for non-utilities)
Segmented by 4 Digit Plant Code	Segmented by 4 Digit Plant Code
Fossil fired steam plants over 50 MW	All utilities
Includes detailed fuel type, including subbituminous	Includes detailed fuel type but bituminous and subbituminous are reported as bituminous
Contains origin information of coal	No origin information
Not separated by NERC region	Divided by NERC region
Annual information	Monthly information
Fuel purchase data	Fuel consumption and generation data

The linkage of these two data sets provided the necessary detail to track the type and origin of coal purchased by plants over 50 MW in the MAIN and MAPP regions during the year 2000, as shown in Table A-2. These 79 large fossil fired plants made up about 95% of the fossil fuel consumption for 2000 in MAIN and MAPP.[44]

Table A-2. SUMMARY OF COAL PURCHASED BY MAIN/MAPP PLANTS OVER 50 MW

	Specific Coal (in 2000)			
State of Coal Origin	**Bituminous**	**Lignite**	**Subbituminous**	**% of Total**
Colorado	1.56%		0.01%	1.57%
Illinois	5.54%			5.54%
Indiana	0.34%			0.34%
Kentucky	0.36%			0.36%
Montana		0.23%	8.15%	8.38%
North Dakota		18.28%		18.28%
Pennsylvania	0.44%			0.44%
Utah	0.20%			0.20%
Virginia	0.05%			0.05%
West Virginia	0.03%			0.03%
Wyoming	0.22%		64.61%	64.83%
Grand Total	8.73%	18.51%	72.76%	100.00%

Note: 79 Unique Plant Codes.

To confirm that the pattern of coal purchased in a year corresponds to the pattern of coal consumed in the same year, we repeated the same summary for the EIA 906 (consumption)

[44] EIA 906 data cross-referenced with EIA 423.

data set (Table A-3). The small difference in the coal purchased and the coal consumed[45] confirms that plants consume roughly the same amount of fuel as they purchase in the same year.

Table A-3. SUMMARY OF COAL CONSUMED BY MAIN/MAPP PLANTS OVER 50 MW

	Total Coal Consumption for 2000	
Fuel Type	**Total**	**Difference from Purchase Data**
Bituminous*	82.75%	1.26%
Lignite	17.25%	
Grand Total	100.00%	

* EIA 906 reported subbituminous and bituminous coal together.

A.1.2 Mercury Content of Coal

The information on the origin and type of coal allowed us to estimate the average mercury content of coal fired in the region. On average coal consumed in the MAIN and MAPP region in 2000 contained 5.7940 pounds of mercury per trillion (10^{12}) BTU. This value was based on the proportion of coals consumed in the region for 2000 and additional data on the average mercury content of each type of coal.

Data on the mercury content of each type of coal was found on the EPA Air Toxics website[46]. In 1999 the EPA collected around 40,000 coal quality samples from steam generating utilities across the country. Over 30,000 samples were collected for the states selling fuel to MAIN and MAPP in 2000. This data, referred to as ICR (Information Collection Request), reported the mercury content (parts per million [ppm]), the energy content (Btu per pound), and origin of coals fired across the nation. It is the most comprehensive data set on coal quality available today.[47]

For this analysis, the ICR data was filtered to include only the eleven states selling coal to utilities in MAIN and MAPP in 2000 (see Table A-2 for a list of states). For these samples, the mean mercury content, the range, and the average energy content for each type of coal from

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[45] There is a 1.26% difference between Bituminous + Subbituminous purchased and bituminous consumed—where the bituminous consumed includes subbituminous.

46 UTILTOX Coal Analysis Results (all Four Quarters, just states selling coal to MAIN and MAPP (see Table 2 for list of states) http://www.epa.gov/ttn/atw/combust/utiltox/utoxpg.html#DA2.

[47] COALQUAL from USGS had been used previously which contained a tenth of the number of samples (4350 samples compared to 31,281) and were core, or channel samples from mines. They are the basis for the AP-42 emission factors used by EPA.

each state was calculated and is presented in Table A-4. These values were consistent with EPA reporting on the data.[48]

Table A-4. AVERAGE MERCURY CONTENT OF FUELS SOLD TO MAIN/MAPP

	1999 ICR Averages for MAIN and MAPP Coal Providers[49]	1999 ICR Averages for All Coal Samples[50]	1997 U.S. EPA Calculated Emissions Factors[51]
Fuel–Coal	**Pounds of Hg/10^{12} Btu**	**Pounds of Hg/10^{12} Btu**	**Pounds of Hg/10^{12} Btu**
Bituminous	6.26	7.05	16
Subbituminous	5.15	5.00	10
Lignite	8.65	7.94	21

As demonstrated in Table A-4, the estimated mercury content of coals purchased in MAIN and MAPP are considerably lower than the previously accepted national average reported in a series of 1997 EPA reports on mercury, including the *1997 EPA Report to Congress on Mercury*, and *Locating and Estimating Emissions from Sources of Mercury and Mercury Compounds*. The most significant difference in these two estimates is due to the preparation of the coal. The ICR samples were provided by the utilities on prepared coal as it entered the combustion process. The earlier emissions factors were based on the mercury content of coal as it was mined. Use of the ICR data therefore eliminates the uncertainty of additional adjustments to account for coal preparation.

The average mercury content of each type of coal and the proportion of that coal purchased in the region provided enough information to calculate a weighted average for the MAIN/MAPP region. The average mercury content of each type of coal in each state was simply multiplied by its proportion of the total coal purchased in the region.

For example, Illinois has three types of bituminous coal based on sulfur content: high, low, and regular. The average mercury content for these three types of coal is 0.0803 ppm. 5.54% of the coal purchased by MAIN and MAPP was Illinois bituminous. These two values were multiplied to produce a weighted average of 0.00445. When added to similarly calculated values of the other states and other types of coal, a weighted average of .07331 ppm of mercury for the region is derived. Based on the range, the maximum weighted average for the region is: 0.4195 ppm and the minimum is: 0.0562 ppm.

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48 UTILTOX-NWF Meeting Presentation, 9/8/00 http://www.epa.gov/ttn/atw/combust/utiltox/nwf_9_8.pdf.

49 ICR coal data and EIA data supported by ICR Presentation to NWR, 1999.

50 UTILTOX-NWF Meeting Presentation, September 8, 2000. http://www.epa.gov/ttn/atw/combust/utiltox/nwf_9_8.pdf.

51 Locating and Estimating Emissions from Mercury and Mercury Compounds, EPA, December 1997. Table 6-6, 6-5, 6-4.

The average mercury content, expressed in ppm for each type of coal, was then converted to pounds of mercury for each trillion Btu of energy consumed.

$$\text{ppm of Hg} / (\text{Btu/lb of coal} \ast 1\text{x}10^{6} \text{ lbs of coal}) = \text{lbs of Hg}/10^{12} \text{ Btu}$$

A weighted average of **5.7940 lbs of Hg/10^{12} Btu** was established for the coals used in this region. Averages for each type of coal can also be seen in Table A-5. The range for this value is: 4.4531 lbs of Hg/10^{12} Btu to 33.261 lbs of Hg/10^{12} Btu.

Table A-5. CALCULATION OF MERCURY CONTENT FOR MAIN AND MAPP

# of Samples	State of Origin	Coal Type	Average Hg	Min.	Max.	**Average Hg for Coal Types**	% of Coal Purchased	Weighted Average for MAIN/MAPP	Average Btu/lb	Lbs of Hg/ 10^{12} Btu
727	Colorado	Bituminous	0.0457	0.0050	0.2300	**0.0457**	0.0156	0.00071359	12540.23	3.6477
172		Subbituminous	0.0254	0.0100	0.1100	**0.0254**	0.0001	2.5407E-06	12411.34	2.0471
2105	Illinois	Bituminous	0.0826	0.0070	0.3900	**0.0803**	0.0554	0.00445049	12671.48	6.3397
254		Bituminous–High Sulfur	0.0702	0.0300	0.1800					
69		Bituminous–Low Sulfur	0.0882	0.0500	0.1400					
3		Subbituminous	0.0250	0.0250	0.0250	**0.0250**	0.0000	0	12137.40	2.0597
1411	Indiana	Bituminous	0.0766	0.0090	0.3400	**0.0898**	0.0034	0.00030516	12985.54	6.9117
166		Bituminous–High Sulfur	0.0933	0.0100	0.1600					
0		Bituminous–Low Sulfur	0.0993	0.0670	0.1430					
5340	Kentucky	Bituminous	0.0946	0.0100	0.6200	**0.0838**	0.0036	0.0003015	13698.96	6.1137
26		Bituminous–Low Sulfur	0.0350	0.0200	0.0700					
111		Bituminous–Low Sulfur	0.1216	0.0200	0.9120					
254		Subbituminous	0.1129	0.3430	0.0250	**0.1129**	0.0000	0	12963.37	8.7081
41	Montana	Lignite	0.0967	0.0600	0.1640	**0.0967**	0.0023	0.00022237	10702.17	9.0340
878		Subbituminous	0.0599	0.0100	0.9000	**0.0599**	0.0815	0.00488201	12362.44	4.8455
383	North Dakota	Lignite	0.0874	0.2630	0.0300	**0.0874**	0.1828	0.01598476	10573.08	8.2704
3072	Pennsylvania	Bituminous	0.1937	0.0010	1.1200	**0.1962**	0.0044	0.00086316	13433.36	1.4603
63		Bituminous–High Sulfur	0.2283	0.0100	0.5570					
112		Bituminous–Low Sulfur	0.1665	0.0200	0.4800					
669	Utah	Bituminous	0.0569	0.0034	0.4100	**0.0485**	0.0020	9.6908E-05	12757.39	3.7981
4		Bituminous–Low Sulfur	0.0400	0.0200	0.0500					
1482	Virginia	Bituminous	0.0860	0.0100	0.3200	**0.0792**	0.0005	3.9611E-05	14056.26	5.6361
2		Bituminous–Low Sulfur	0.1000	0.0500	0.1500					
6		Bituminous–Low Sulfur	0.0517	0.0300	0.0700					
7142	West Virginia	Bituminous	0.1133	0.0060	0.6660	**0.0919**	0.0003	2.7574E-05	13490.64	6.8130
10		Bituminous–High Sulfur	0.0814	0.0550	0.1100					
40		Bituminous–Low Sulfur	0.081	0.0100	0.2400					
24		Subbituminous	0.0965	0.0440	0.2440	**0.0965**	0.0000	0	13025.62	7.4053
113	Wyoming	Bituminous	0.0358	0.0100	0.4000	**0.0309**	0.0022	6.8049E-05	12573.58	2.4600
135		Bituminous–Low Sulfur	0.0261	0.0140	0.0450					
6467		Subbituminous	0.0698	0.0080	0.4900	**0.0698**	0.6461	0.04511199	12008.22	5.8145
31281			0.0852	0.0397	0.3158	**0.1015**	1.0002	0.0731	12611.24	5.7940

A.1.3 Other Fuels

Mercury may be found in other types of fuel besides coal. Most other fuel sources release considerably lower concentrations of mercury per unit of energy produced, with the exception of municipal solid waste. Table A-6 shows the estimated mercury content of natural gas, oil, wood, and municipal waste according to the EPA.[52] While the origin of these fuels may influence their mercury content, no data is available to make such a distinction.

Table A-6. ESTIMATED MERCURY CONTENT OF NON-COAL FUELS

Fuel Type	Mercury Concentration Pounds of Hg/10^{12} Btu
Oil	0.48
Natural Gas	0.00014
Wood Waste	0.57
Municipal Solid Waste	71.85

A.2 PREPARATION OF COAL BEFORE FIRING (CLEANING)

As noted earlier, the ICR samples were reported "as fired" (i.e. cleaned) as opposed to "as mined" (ICR Presentation, pg 11). If the samples had been reported "as mined" an additional adjustment would have to be added to the equation. Cleaning of coal is reported to remove around 20% of the mercury on average and in some cases over 60%.[53]

A.3 HEAT RATE

The heat rate determines the rate at which the fuel is combusted and consequently affects the rate of mercury emission. Plants reported the heat rate of the fuel burned in the EPA Acid Rain data set.

A.4 BOILER TYPE AND CONTROL TECHNOLOGY

The type of boiler and existing control technologies also has a significant influence on the amount of mercury that is released to the atmosphere. Even though the control technologies are not designed for mercury reduction, some of the chemistry and mechanics used to trap particulate matter and reduce NOx and SOx emissions also reduces the emission of mercury. EPA has summarized these effects with the development of emission modification factors (EMF) based on various plant configurations and the type of coal.

An EMF is the ratio of outlet mercury concentration to inlet mercury concentration and depends on the type of boiler, the control technologies installed at the plant, and may also consider the type of fuel. The percentage of mercury reduction achieved compared to the inlet

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[52] Documentation of EPA Modeling Applications (V.2.1) *Using the Integrated Planning Model*, page 5-11, Table 5.6; EPA 430/R-02-004, March 2002, http://www.epa.gov/airmarkets/epa-ipm/chapter5.pdf.

[53] EPA 1997 Mercury Report to Congress, Table 4-3.

rate during combustion and flue-gas treatment is (1-EMF).[54] We assumed that all of the mercury in the fuel is released into the flue gas.

Mercury In the Flue Gas (after combustion)	x	EMF	=	Mercury Released to the Atmosphere	15% less mercury leaving the system than entered the system.
100	**x**	**0.85**	**=**	**85**	

For example, an EMF of 0.85 means that the mercury released is 15% less than mercury entering the system. An EMF of 1 means the same amount of mercury that entered the system was released to the atmosphere.

EMFs were developed by EPA as part the process to set emission standards for mercury by 2004.[55] Mercury emissions from 81 participating utilities were tracked to develop estimates of the influence of boiler type and control technologies for Particulate Matter (PM), SO_2 and NOx on mercury emission. This is the most comprehensive data set on mercury emissions developed to date.[56]

Each plant configuration has an associated EMF factor for either bituminous or subbituminous coal. Lignite coal was reported as subbituminous category because they share similar EMFs.[57] No EMF factors are reported for non-coal fuel sources.

Based on the research presented in the first section, over 90% of the coal consumed in the combined MAIN and MAPP region was subbituminous or lignite.[58] For this analysis, the EMF for subbituminous coal was deemed most appropriate for the associated boiler and control configurations.

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[54] Documentation of EPA Modeling Applications (V.2.1) Using the Integrated Planning Model, page 5-11.

[55] EPA Mercury Regulations on Electric Steam Generating Units.

[56] A detailed list of the EMFs that resulted from this study can be found in Table 5.7a in *Documentation of EPA Modeling Applications (V.2.1) Using the Integrated Planning Model.*

[57] Documentation of EPA Modeling Applications (V.2.1) Using the Integrated Planning Model Table 5.7a. pg 5-11 to 5-12.

[58] EIA 423, 2000.

The number of plant configurations for which there is an EMF is significantly smaller than the number of possible configurations reported in the Acid Rain Data set. This is mostly due to the variety of control technologies reported for the Acid Rain series. For this reason, as well as coding differences, the Acid Rain data and the EMF data had to be matched. A list of the matches and the accompanying EMFs can be found in Table A-8 at the end of this appendix.[59]

A.5 CALCULATING PLANT-LEVEL HOURLY MERCURY EMISSIONS

The output of the process described above was a set of EMFs for a wide range of fuel and control technologies. The EMFs were then used to calculate emissions from each plant in the Acid Rain data for each hour of the year.

The Acid Rain Database provides the basic information on the plants operating in these two NERC regions. This data is supplemented with information about the probable content of mercury entering the system and the likely release of mercury as it passes through the system.

The EPA Acid Rain data set provides quarterly information on the configuration of the units being monitored including fuel type, boiler type, and control technologies installed for NOx, SO_2, and PM. The heat input rate and load of the unit in operation are reported hourly. The average mercury content of fuel and the EMF are provided by supplementary sources described in the preceding sections.

The mercury content of the fuel, heat rate, EMFs, and percentage of each hour a generator was operating were used together to calculate emissions from each plant for each hour of the year using the formula shown in Figure A-1.

Multiplying the mercury content of the fuel by the heat rate produces gross emissions in pounds/hour. Multiplying that by the EMF produces net emissions (again in pounds/hour) after the control technology was applied and assuming the plant was operating at capacity for the full hour. Multiplying that number by the fraction of the hour the generator was running (the capacity factor) produces the pounds of mercury emitted by the generator during that hour.

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[59] The effectiveness of an Electro Static Precipitator (ESP) in removing mercury is affected by whether it is on the "hot-side" or on the "cold-side." The Acid Rain data does not specify which side the ESPs are on, as a result, we have assumed the ESPs are on the "cold-side" in order to provide a conservative estimate—with the lowest possible emissions avoided.

Figure A-1. FORMULA FOR CALCULATING MERCURY EMISSIONS

Definition	Mercury Content of the Fuel	x	Heat Rate	x	Adjust Units	x	Emissions Control Factor	=	Emissions	x	Fraction of the hour running (capacity factor)	=	Emissions in the current hour
Units	$\frac{\text{Lbs of HG}}{10^{12}\text{ Btu}}$	x	$\frac{10^{6}\text{ Btu}}{\text{Hour}}$	x	$\frac{1}{10^{6}}$	x	Unitless	=	$\frac{\text{Lbs of HG}}{\text{Hour}}$	x	Hours	=	Lbs of HG

Definitions

Mercury Content of the Fuel (Lbs/Btu)	Heat Rate (Btu/Hour)		
Gross Emissions (Lbs/Hour)			
Net Emissions after control technology applied and assuming generating at capacity for the full hour (Lbs/MWh)			
Net Emissions after control technology applied for the current hour taking capacity factor into account (Lbs of HG)			

To determine the appropriate EMF the boiler and control configuration reported in the Acid Rain Data was matched with the “best fit” EMF.

If the fuel was oil, natural gas, wood, or municipal waste, we assume that the mercury content of the fuel is emitted in its entirety since no emission modification factors for these fuels are available. For those fuels the EMF was one (1). For coal, we chose the appropriate EMF based on the boiler and control configuration reported in the Acid Rain data, using the criteria shown in Table A-8.

A.6 BENEFITS OF THIS METHOD

The approach we took to calculating mercury emissions offers several advantages over other approaches typically used, as follows.

- The coal mercury content is region specific, so the actual mercury going into combustion should be more accurate than national averages.
- Using the Acid Rain EPA data set allows for seasonal and time of day estimates for emissions.
- Provides an estimate for the MAIN and MAPP NERC regions rather than just emissions from plants within the state of Wisconsin, as is collected by DNR.
- This method uses the latest information in mercury emissions and coal quality, which should be a more accurate reflection of actual emissions than emissions based on AP-42 emissions factors.
- Coal quality samples are proximate to the time the fuel was purchased and consumed. They more accurately reflect the mercury content of coal being mined and combusted for this year since the samples are from 1999 coal and the coal was combusted in 2000.

A.7 ASSUMPTIONS

This method depends on the following assumptions.

- The data sets used contain information on plants that provide 95% of the power to the region. Thus, we assume that the plants providing the remaining 5% using coal use the same proportions of bituminous, subbituminous, and lignite from the same origins as the 79 plants of over 50 MW in MAIN and MAPP for 2000 used for these calculations.
- The Utility Toxics data set for coal quality is an accurate reflection of the coals being mined and combusted for 2000 though the samples are from 1999.
- A coal type from a particular state is fairly consistent in mercury content and Btu/lb across that state. (Thus we presume that seams do not vary considerably if there is more than one seam in a state. County or seam data may be more accurate.)
- The unit configurations provided in the EPA Acid Rain data are consistent for all four quarters. Units use their primary fuel when they are in operation.

A.8 ANNUAL EMISSIONS SOURCES

Toxics Release Inventory Program (TRI) (EPA)
http://www.epa.gov/tri/tridata/state_data_files.htm#doc.

Wisconsin Department of Natural Resources, Air Management
http://www.dnr.state.wi.us/org/aw/air/reg/mercury/techdocs.htm.

E-GRID 2000 (EPA), Emissions and Generation Resources Integrated Database 2000 (V.2.0).

A.9 REFERENCES

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U.S. EPA, 2002, Documentation of EPA Modeling Applications (V.2.1). *Using the Integrated Planning Model*. EPA 430/R-02-004 (March 2002).

Table A-8. EMISSION MODIFICATION FACTORS FOR UNIT CONFIGURATION

Boiler	Particulate Control	NOx Control	SO2 Control	SUBBITUMINOUS (LIGNITE) EMF
C	ESP	Blank	DL	0.85
C	ESP	Blank	Blank, DA, FBL, MO, O, SB, WLS	0.85
C	ESP	Blank	WL	0.6
C	ESP	SCR	DL	0.85
C	ESP	SCR	Blank, DA, FBL, MO, O, SB, WLS	0.85
C	ESP	SCR	WL	0.05
C	ESP	SNCR	WL	0.1
C	ESP	Other, CM, DLNB, H2O, LNB, LNBO, LNC1, LNC2, LNC3, LNCB, NH3, OFA, STM	Blank, DA, FBL, MO, O, SB, WLS	0.85
C	B	Blank	DL	0.95
C	B	Blank	Blank, DA, FBL, MO, O, SB, WLS	0.95
C	B	Blank	WL	0.95
C	B	SCR	DL	0.95
C	B	SCR	Blank, DA, FBL, MO, O, SB, WLS	0.95
C	B	SCR	WL	0.05
C	B	SNCR	DL	0.95
C	B	SNCR	WL	0.1
C	B	Other, CM, DLNB, H2O, LNB, LNBO, LNC1, LNC2, LNC3, LNCB, NH3, OFA, STM	Blank, DA, FBL, MO, O, SB, WLS	0.95
C	Blank, O, C	Blank	DL	1
C	Blank, O, C	Blank	Blank, DA, FBL, MO, O, SB, WLS	1
C	Blank, O, C	Blank	Blank, DA, FBL, MO, O, SB, WLS	1
C	Blank, O, C	Blank	WL	0.6
C	Blank, O, C	SCR	DL	1
C	Blank, O, C	SCR	Blank, DA, FBL, MO, O, SB, WLS	1
C	Blank, O, C	SCR	WL	0.05
C	Blank, O, C	SNCR	WL	0.1
C	Blank, O, C	Other, CM, DLNB, H2O, LNB, LNBO, LNC1, LNC2, LNC3, LNCB, NH3, OFA, STM	Blank, DA, FBL, MO, O, SB, WLS	1
C	WS	Blank	Blank, DA, FBL, MO, O, SB, WLS	1
CFB	ESP	Blank	Blank, DA, FBL, MO, O, SB, WLS	0.65
CFB	ESP	Blank	WL	0.65
CFB	ESP	SCR	WL	0.05
CFB	ESP	SNCR	WL	0.1
CFB	B	Blank	Blank, DA, FBL, MO, O, SB, WLS	0.45
CFB	B	Blank	WL	0.45
CFB	B	SCR	Blank, DA, FBL, MO, O, SB, WLS	0.45
CFB	B	SCR	WL	0.05
CFB	B	SNCR	WL	0.1
CFB	Blank, O, C	Blank	DL	0.45

Boiler	Particulate Control	NOx Control	SO2 Control	SUBBITUMINOUS (LIGNITE) EMF
CFB	Blank, O, C	Blank	Blank, DA, FBL, MO, O, SB, WLS	1
CFB	Blank, O, C	Blank	Blank, DA, FBL, MO, O, SB, WLS	1
CFB	Blank, O, C	Blank	WL	1
CFB	Blank, O, C	SCR	DL	0.45
CFB	Blank, O, C	SCR	Blank, DA, FBL, MO, O, SB, WLS	1
CFB	Blank, O, C	SCR	WL	0.05
CFB	Blank, O, C	SNCR	DL	0.45
CFB	Blank, O, C	Other, CM, DLNB, H2O, LNB, LNBO, LNC1, LNC2, LNC3, LNCB, NH3, OFA, STM	Blank, DA, FBL, MO, O, SB, WLS	1
WVF, AF, CB, DTF, WBT	ESP	Blank	DL	0.85
WVF, AF, CB, DTF, WBT	ESP	Blank	Blank, DA, FBL, MO, O, SB, WLS	0.85
WVF, AF, CB, DTF, WBT	ESP	Blank	WL	0.85
WVF, AF, CB, DTF, WBT	ESP	SCR	Blank, DA, FBL, MO, O, SB, WLS	0.85
WVF, AF, CB, DTF, WBT	ESP	Other, CM, DLNB, H2O, LNB, LNBO, LNC1, LNC2, LNC3, LNCB, NH3, OFA, STM	Blank, DA, FBL, MO, O, SB, WLS	0.85
WVF, AF, CB, DTF, WBT	B	Blank	DL	0.95
WVF, AF, CB, DTF, WBT	B	Blank	Blank, DA, FBL, MO, O, SB, WLS	0.95
WVF, AF, CB, DTF, WBT	B	Blank	WL	0.95
WVF, AF, CB, DTF, WBT	B	SCR	DL	0.95
WVF, AF, CB, DTF, WBT	B	SCR	Blank, DA, FBL, MO, O, SB, WLS	0.95
WVF, AF, CB, DTF, WBT	B	SCR	WL	0.05
WVF, AF, CB, DTF, WBT	B	SNCR	DL	0.95
WVF, AF, CB, DTF, WBT	B	SNCR	WL	0.1
WVF, AF, CB, DTF, WBT	Blank, O, C	Blank	DL	1
WVF, AF, CB, DTF, WBT	Blank, O, C	Blank	Blank, DA, FBL, MO, O, SB, WLS	1
WVF, AF, CB, DTF, WBT	Blank, O, C	Blank	WL	1
WVF, AF, CB, DTF, WBT	Blank, O, C	SCR	blank or DA or FBL or MO or O or SB or WLS	1
WVF, AF, CB, DTF, WBT	Blank, O, C	SCR	WL	0.05
WVF, AF, CB, DTF, WBT	Blank, O, C	SNCR	WL	0.1
WVF, AF, CB, DTF, WBT	Blank, O, C	Other, CM, DLNB, H2O, LNB, LNBO, LNC1, LNC2, LNC3, LNCB, NH3, OFA, STM	Blank, DA, FBL, MO, O, SB, WLS	1
DB, T, WBF	ESP	Blank	DL	0.85
DB, T, WBF	ESP	Blank	DL	0.85
DB, T, WBF	ESP	Blank	Blank, DA, FBL, MO, O, SB, WLS	0.85
DB, T, WBF	ESP	Blank	WL	0.65
DB, T, WBF	ESP	SCR	DL	0.85
DB, T, WBF	ESP	SCR	Blank, DA, FBL, MO, O, SB, WLS	0.85
DB, T, WBF	ESP	SCR	WL	0.05
DB, T, WBF	ESP	SNCR	DL	0.85
DB, T, WBF	ESP	SNCR	WL	0.1
DB, T, WBF	ESP	Other, CM, DLNB, H2O, LNB, LNBO, LNC1, LNC2, LNC3, LNCB, NH3, OFA, STM	Blank, DA, FBL, MO, O, SB, WLS	0.85
DB, T, WBF	ESP and B	Blank	Blank, DA, FBL, MO, O, SB, WLS	0.75

Boiler	Particulate Control	NOx Control	SO2 Control	SUBBITUMINOUS (LIGNITE) EMF
DB, T, WBF	ESP and B	Blank	WL	0.3
DB, T, WBF	ESP and B	SCR	Blank, DA, FBL, MO, O, SB, WLS	0.75
DB, T, WBF	ESP and B	Other, CM, DLNB, H2O, LNB, LNBO, LNC1, LNC2, LNC3, LNCB, NH3, OFA, STM	Blank, DA, FBL, MO, O, SB, WLS	0.75
DB, T, WBF	ESP and B	Blank	DL	0.75
DB, T, WBF	ESP and B	SCR	DL	0.75
DB, T, WBF	ESP and B	SCR	WL	0.05
DB, T, WBF	ESP and B	SNCR	WL	0.1
DB, T, WBF	B	Blank	DL	0.75
DB, T, WBF	B	Blank	Blank, DA, FBL, MO, O, SB, WLS	0.75
DB, T, WBF	B	Blank	WL	0.3
DB, T, WBF	B	SCR	DL	0.75
DB, T, WBF	B	SCR	Blank, DA, FBL, MO, O, SB, WLS	0.75
DB, T, WBF	B	SCR	WL	0.05
DB, T, WBF	B	SNCR	DL	0.75
DB, T, WBF	B	SNCR	WL	0.1
DB, T, WBF	B	Other, CM, DLNB, H2O, LNB, LNBO, LNC1, LNC2, LNC3, LNCB, NH3, OFA, STM	Blank, DA, FBL, MO, O, SB, WLS	0.75
DB, T, WBF	Blank, O, C	Blank	DL	0.85
DB, T, WBF	Blank, O, C	Blank	Blank, DA, FBL, MO, O, SB, WLS	1
DB, T, WBF	Blank, O, C	Blank	Blank, DA, FBL, MO, O, SB, WLS	1
DB, T, WBF	Blank, O, C	Blank	WL	0.7
DB, T, WBF	Blank, O, C	Blank	WL	0.7
DB, T, WBF	Blank, O, C	SCR	DL	0.7
DB, T, WBF	Blank, O, C	SCR	Blank, DA, FBL, MO, O, SB, WLS	1
DB, T, WBF	Blank, O, C	SCR	WL	0.05
DB, T, WBF	Blank, O, C	SNCR	DL	0.85
DB, T, WBF	Blank, O, C	SNCR	WL	0.1
DB, T, WBF	Blank, O, C	Other, CM, DLNB, H2O, LNB, LNBO, LNC1, LNC2, LNC3, LNCB, NH3, OFA, STM	Blank, DA, FBL, MO, O, SB, WLS	1
DB, T, WBF	Blank, O, C	Other, CM, DLNB, H2O, LNB, LNBO, LNC1, LNC2, LNC3, LNCB, NH3, OFA, STM	Blank, DA, FBL, MO, O, SB, WLS	1
DB, T, WBF	WS	Blank	Blank, DA, FBL, MO, O, SB, WLS	1
DB, T, WBF	WS	SCR	Blank, DA, FBL, MO, O, SB, WLS	1
S	ESP	Blank	DL	0.85
S	ESP	Blank	Blank, DA, FBL, MO, O, SB, WLS	0.85
S	ESP	Blank	WL	0.65
S	ESP	SCR	DL	0.85
S	ESP	SCR	Blank, DA, FBL, MO, O, SB, WLS	0.65
S	ESP	Other, CM, DLNB, H2O, LNB, LNBO, LNC1, LNC2, LNC3, LNCB, NH3, OFA, STM	Blank, DA, FBL, MO, O, SB, WLS	0.65
S	B	Blank	DL	0.45

Boiler	Particulate Control	NOx Control	SO2 Control	SUBBITUMINOUS (LIGNITE) EMF
S	B	Blank	Blank, DA, FBL, MO, O, SB, WLS	0.45
S	B	Blank	WL	0.45
S	B	SCR	DL	0.45
S	B	SCR	Blank, DA, FBL, MO, O, SB, WLS	0.45
S	B	Other, CM, DLNB, H2O, LNB, LNBO, LNC1, LNC2, LNC3, LNCB, NH3, OFA, STM	Blank, DA, FBL, MO, O, SB, WLS	0.45
S	Blank, O, C	Blank	DL	1
S	Blank, O, C	Blank	Blank, DA, FBL, MO, O, SB, WLS	1
S	Blank, O, C	Blank	WL	1
S	Blank, O, C	SCR	DL	1
S	Blank, O, C	SCR	Blank, DA, FBL, MO, O, SB, WLS	1
S	Blank, O, C	Other, CM, DLNB, H2O, LNB, LNBO, LNC1, LNC2, LNC3, LNCB, NH3, OFA, STM	Blank, DA, FBL, MO, O, SB, WLS	1

Table A-9. GUIDE TO THE EMF ASSIGNMENTS

Acid Rain Code	Acid Rain Data Boiler Type	Base Case Match
AF	Arch-fired boiler (coal units only)	Other
C	Cyclone boiler	Cyclone
CB	Cell burner boiler (coal units only)	Other
CFB	Circulating fluidized bed boiler	FBC
DB	Dry bottom wall-fired boiler	PC
DTF	Dry bottom turbo-fired boiler (coal units only)	Other
DVF	Dry bottom vertically-fired boiler (coal units only)	
OB	Other boiler	Other
S	Stoker (coal and wood units only)	S
T	Tangentially-fired	PC
WBF	Wet bottom wall-fired boiler (coal units only)	PC
WBT	Wet bottom turbo-fired boiler (coal units only)	Other
WVF	Wet bottom vertically-fired boiler (coal units only)	Other

Acid Rain Code	NOX Control	Base Case Match
CM	Combustion Modification	SNCR/Other
DLNB	Dry Low NOx Burners (Turbines only)	SNCR/Other
H2O	Water Injection (Turbines and Cyclone Boilers only)	SNCR/Other
LNB	Low NOx Burner Technology (Dry Bottom Boilers only)	SNCR/Other
LNBO	Low NOx Burner Technology with Overfire Air (Dry Bottom Boilers only)	SNCR/Other
LNC1	Low NOx Burner Technology with Close-coupled OFA (Tangentially fired units only)	SNCR/Other
LNC2	Low NOx Burner Technology with Separated OFA (Tangentially fired units only)	SNCR/Other
LNC3	Low NOx Burner Technology with Close-coupled and Separated OFA (Tangentially fired units only)	SNCR/Other
LNCB	Low NOx Burner Technology for Cell Burners	SNCR/Other
NH3	Ammonia Injection	SNCR/Other
O	Other	SNCR/Other
OFA	Overfire Air	SNCR/Other
SCR	Selective Catalytic Reduction	SCR
SNCR	Selective Non-catalytic Reduction	SNCR
STM	Steam Injection	SNCR/Other
	Blank	No control

Acid Rain Code	SO2 Control	Base Case Match
DL	Dry Lime FDG	Dry FGD
WL	Wet Lime FDG	Wet FGD
DA	Dual Alkali	No control
FBL	Fluidized Bed Limestone Injection	No control
MO	Magnesium Oxide	No control
O	Other	No control
SB	Sodium Based	No control
WLS	Wet Limestone	No control
	Blank	No control

Acid Rain Code	Particulate Control	Base Case Match
B	Baghouse	Fabric Filter
ESP	Electrostatic Precipitator	ESP Cold Side and Hot Side
WS	Wet Scrubber	PM Scrubber
O	Other	No control
C	Cyclone	No control
	Blank	No control

APPENDIX B: PROJECTION OF EMISSION CREDIT PRICES

This appendix provides a projection of emission credit prices that underlies some of the analysis in Chapter 6.

Projections of Emission Credit Prices Under "Clear Skies" Scenario with Emerging GHG Market

Source: M-POM Model, PA Consulting Group

Current spot market prices used for 2003. M-POM projections used for 2004-2012
M-POM output is in constant 2000$. Convert to Jan. 03 dollars as follows:

GDP Price Deflator, 3Q 2000	107.2
GDP Price Deflator, 1Q 2003	111.5
Conversion factor to Jan.03 dollars	1.04

= convert to 2003$=

	MPOM Low Price Scenario	MPOM High Price Scenario	MPOM Low Price Scenario	MPOM High Price Scenario	Emission Reductions	Annual Projected Value (Low)	Annual Projected Value (High)	Multi-Yr Projected Value (Low)	Multi-Yr Projected Value (High)	
SO2	2000$/ton	2000$/ton	2003$/ton	2003$/ton	tons					
2003	130	130	130	130	1,867	242,691	242,691	242,691	242,691	*[2003]*
2004	200	236	208	245	1,867	388,348	458,251	1,553,393	1,833,003	*[2004-07]*
2008	253	298	263	310	1,867	491,260	578,639	982,521	1,157,278	*[2008-09]*
2010	284	335	295	348	1,867	551,454	650,483	1,102,909	1,300,966	*[2010-11]*
2012	319	377	332	392	1,867	619,415	732,036	619,415	732,036	*[2012]*
								-------------	-------------	
							Total	4,500,929	5,265,975	
NOx East	2000$/ton	2000$/ton	2003$/ton	2003$/ton	tons					
2003	0	0	0	0	813.4	0	0	0	0	*[2003]*
2004	0	0	0	0	813.4	0	0	0	0	*[2004-07]*
2008	1345	1406	1,399	1,462	813.4	1,137,839	1,189,443	2,275,677	2,378,886	*[2008-09]*
2010	1512	1580	1,573	1,643	813.4	1,279,117	1,336,643	2,558,233	2,673,286	*[2010-11]*
2012	1699	1776	1,767	1,847	813.4	1,437,314	1,502,454	1,437,314	1,502,454	*[2012]*
								-------------	-------------	
							Total	6,271,225	6,554,627	
		MPOM High Price Scenario	U.S. EPA Low Price Scenario	MPOM High Price Scenario						
Mercury		2000$/lb	2003$/lb	2003$/lb	pounds					
2003		0	0	0	15.9	0	0	0	0	*[2003]*
2004		0	0	0	15.9	0	0	0	0	*[2004-07]*
2008		0	0	0	15.9	0	0	0	0	*[2008-09]*
2010		113,500	16,000	118,053	15.9	254,400	1,877,038	508,800	3,754,076	*[2010-11]*
2012		116,000	16,000	120,653	15.9	254,400	1,918,382	254,400	1,918,382	*[2012]*
								-------------	-------------	
							Total	763,200	5,672,458	
			PA Survey - Low Price Scenario	PA Survey - High Price Scenario						
CO2 [Electricity & Natural Gas]			2003$/ton	2003$/ton	tons					
2003			1	2	362,872	362,872	725,745	362,872	725,745	*[2003]*
2004			1	2	362,872	362,872	725,745	1,451,489	2,902,979	*[2004-07]*
2008			2	4	362,872	725,745	1,451,489	1,451,489	2,902,979	*[2008-09]*
2010			5	10	362,872	1,814,362	3,628,723	3,628,723	7,257,447	*[2010-11]*
2012			5	10	362,872	1,814,362	3,628,723	1,814,362	3,628,723	*[2012]*
								-------------	-------------	
							Total	8,708,936	17,417,872	
					Total for 2003 for 4 emissions			605,564	968,436	
					Total for 2012 for 4 emissions			4,125,491	7,781,597	
					Total for 2003-2012 for 4 emissions			20,244,290	34,910,932	

Notes

"MPOM Low Price Scenario" assumes low electricity demand growth and $3/mmbtu natural gas price.
"MPOM High Price Scenario" assumes high electricity demand growth and $4/mmbtu natural gas price.
All "Multi-Year Projected Value" calculations hold price constant in the three multi-year periods, i.e., 2004-07, 2008-09, & 2010-11.
For NOx, this assumes Clear Skies cap on NOx takes effect in 2008.
For Mercury, EPA's price projection is used for the low scenario, given that it is lower than M-POM projection, and M-POM projection is used for high scenario. "Clear Skies" cap takes effect in 2010.
For GHG, PA informal survey of GHG spot market an price projections is used. Includes CO2 reductions from therms saved.

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