CORRESPONDENCE/MEMORANDUM

DATE: April 9, 2007

TO: Members of the Natural Resources Board

FROM: Scott Hassett, Secretary

SUBJECT: Reasonably Available Control Technology (RACT) program for major sources of nitrogen oxides (NO_x) in the moderate ozone nonattainment area and miscellaneous non-substantive corrections to current ch. NR 428 requirements.

Introduction

In June 2004, the US EPA designated ten Wisconsin counties as nonattainment for the 8-hour ozone ambient air quality standard. The counties of Kenosha, Racine, Milwaukee, Waukesha, Washington, Ozaukee, and Sheboygan are designated as "moderate" ozone nonattainment and the counties of Manitowoc, Kewaunee, and Door as "basic." The designation triggered federal Clean Air Act requirements for adopting rules to reduce oxides of nitrogen (NO_x) and volatile organic compound emissions sufficiently to demonstrate attainment of the ozone standard by 2009 in basic areas and 2010 in moderate areas.

The federal Clean Air Act requires implementation of "reasonably available control technology" (RACT) for major stationary sources of NOx and volatile organic compounds (VOC) in the moderate ozone nonattainment area by May 1, 2009. The Department is proposing this rule package to meet the RACT requirement for major sources of NO_x emissions. The Department previously adopted RACT rules for VOC to address the old 1-hour ozone standard. Under the 1-hour standard, the State had a waiver for implementing NOx RACT. No such waiver exists for the 8-hour standard. Therefore, the Department must proceed with developing NOx RACT rules.

To develop the proposed rules, the Department used the flexibility that EPA allows in creating RACT rules. However, these proposed rules do not exceed federal Clean Air Act requirements.

Potential NO_x emission requirements for the basic nonattainment areas are not addressed in this rule package, since NO_x RACT is required in basic areas only if attainment cannot be demonstrated by the 2009 ozone season.

One issue associated with RACT rule development warrants additional attention. EPA allows a state to determine if the Clean Air Interstate Rule (CAIR) satisfies NOx RACT requirements for major utility coal-fired boilers subject to CAIR. This is often referred to as the "CAIR = RACT" determination. This provision is based on EPA's assessment that the CAIR program, on a national basis, achieves greater reductions than the total reductions from a surrogate RACT program only in the nonattainment areas. Department legal staff has identified significant legal issues associated with EPA's assessment. In particular, RACT and CAIR are separate requirements in the Clean Air Act and implementation of CAIR cannot satisfy the RACT requirement. DNR legal staff indicates that both programs must be implemented. See Attachment C for more details.

1. Why is this rule being proposed?

The Department is proposing this rule to comply with the requirements of the federal Clean Air Act to implement a NOx RACT program for major sources in the moderate 8-hour ozone nonattainment

areas. The resulting NO_x emission reductions will directly contribute to achieving attainment of the 8-hour ozone and PM2.5 standards and will aid in meeting future haze requirements.

Additionally, the Department is proposing the rule to make a non-substantive change to ch. NR 428. Section NR 428.05(3)(e) currently sets forth emission limitations for reciprocating engines. The units for the emission limit currently read grams per brake-horsepower (gr /br-hp). The units are corrected in this rule package to read grams per brake-horsepower hour (gr / br-hp-hr). This proposed change in the current language is consistent with the ch. NR 428 rule package adopted by the Board in 2000.

2. Summary of the rule

The proposed rule establishes NO_x RACT emission requirements for major sources in the moderate ozone nonattainment areas. The emission requirements apply to individual stationary combustion units at major sources and must be met by May 1, 2009.

The emission requirements consist of NO_x emission limitations which apply on a year-round basis. The emission limitations are established by source categories with an emission unit size threshold based on available control technologies and cost-effectiveness. The rule contains exemptions from RACT requirements for certain types of emission units demonstrating low operating levels during the ozone season. An additional exemption recognizes that certain smaller emission units are already well controlled under existing NR 428 provisions and no further action is needed in meeting the RACT emission limit. Attachment A provides the technical assessment that supports the Department's proposed rule.

a. General Applicability

The proposed rule affects facilities with the potential to emit 100 tons or more of NO_x per year in the moderate ozone nonattainment areas, but the emission limits apply to individual emission units, such as a boiler or furnace, at the affected facilities. It is possible that an emission unit contributing to a major source's potential to emit may not be subject to a RACT requirement. Likewise, an emission unit identified by a RACT source category, but at a facility with a potential to emit less than 100 tons per year, will not be subject to a RACT requirement.

b. Categorical Emission Limits

The proposed rule establishes NO_x emission rate limits by source category applicable to emission units operating above threshold levels during the ozone season. The proposed source categories, operating levels, and emission limitations are presented in Table 1. The emission limits contained in the proposed rule are a 30-day rolling average requirement applicable on a year-round basis. A unit subject to an emission limitation must demonstrate compliance on an individual basis by May 1, 2009.

Table 1. Proposed NO_x RACT Categorical Emission Limits[1].

Source Category	Capacity Threshold	NO_x Emission Limitation (30 day rolling average)
Solid Fuel-Fired Boiler	=> 1000 mmBtu/hr	Tangential-fired.....0.10 lbs/mmBtu Wall-fired.....0.10 lbs/mmBtu Cyclone-fired .....0.10 lbs/mmBtu Fluidized bed-fired.....0.10 lbs/mmBtu Arch-fired..... 0.18 lbs/mmBtu
	=> 500 – 999 mmBtu/hr	Tangential-fired.....0.15 lbs/mmBtu Wall-fired (low heat release).....0.15 lbs/mmBtu Wall-fired (high heat release).....0.17 lbs/mmBtu Cyclone-fired .....0.15 lbs/mmBtu Fluidized bed-fired.....0.10 lbs/mmBtu Arch-fired..... 0.18 lbs/mmBtu
	=> 250 – 495 mmBtu/hr	Tangential-fired.....0.15 lbs/mmBtu Wall-fired (low heat release).....0.15 lbs/mmBtu Wall-fired (high heat release).....0.17 lbs/mmBtu Cyclone-fired .....0.15 lbs/mmBtu Fluidized bed-fired.....0.10 lbs/mmBtu Arch-fired..... 0.18 lbs/mmBtu Stoker-fired.....0.20 lbs/mmBtu
	50 - 249 mmBtu/hr	Tangential-fired.....0.15 lbs/mmBtu Wall-fired (low heat release).....0.15 lbs/mmBtu Wall-fired (high heat release).....0.17 lbs/mmBtu Cyclone-fired .....0.15 lbs/mmBtu Fluidized bed-fired.....0.10 lbs/mmBtu Arch-fired..... 0.18 lbs/mmBtu Stoker-fired.....0.25 lbs/mmBtu
Gaseous or Liquid Fuel-Fired Boiler	=> 100 mmBtu/hr..... => 100 mmBtu/hr..... => 65 mmBtu/hr.....	Gaseous fuel.....0.08 lbs/mmBtu Distillate oil.....0.10 lbs/mmBtu Residual or waste oil.....0.15 lbs/mmBtu
Lime Kiln (manufacturing)	=> 50 mmBtu/hr	Gaseous fuel.....0.10 lbs/mmBtu Distillate oil.....0.12 lbs/mmBtu Residual oil.....0.15 lbs/mmBtu Coal.....0.60 lbs/mmBtu Coke.....0.70 lbs/mmBtu
Glass Furnace	=> 50 mmBtu/hr	2.0 lbs/ton of glass
Metal Reheat, Galvanizing, and Annealing Furnace	=> 75 mmBtu/hr	0.08 lbs/mmBtu
Asphalt Plants	=> 65 mmBtu/hr	Gaseous fuel.....0.15 lbs/mmBtu Distillate oil.....0.20 lbs/mmBtu Residual or waste oil.....0.27 lbs/mmBtu
Process Heating	=> 100 mmBtu/hr..... => 100 mmBtu/hr..... => 65 mmBtu/hr.....	Gaseous fuel.....0.10 lbs/mmBtu Distillate oil.....0.12 lbs/mmBtu Residual or waste oil.....0.18 lbs/mmBtu
Simple Cycle Combustion Turbine	=> 50 MW	Natural gas.....25 ppmdv @ 15% O_2 Distillate oil.....65 ppmdv @ 15% O_2 Biologically derived fuel..... 35 ppmdv @ 15% O_2

	25 – 49 MW	Natural gas.....42 ppmdv @ 15% O_2 Distillate oil.....96 ppmdv @ 15% O_2 Biologically derived fuel..... 35 ppmdv @ 15% O_2
Combined Cycle Turbine	=> 25 MW..... 10 – 24 MW..... => 25 MW.....	Natural gas.....9 ppmdv @ 15% O_2 Distillate oil.....42 ppmdv @ 15% O_2 Natural gas.....42 ppmdv @ 15% O_2 Distillate oil.....42 ppmdv @ 15% O_2 Biologically derived fuel..... 35 ppmdv @ 15% O_2
Reciprocating Engine	=> 500 horsepower	Rich-burn units.....3.0 gr/bhp-hr Lean-burn units.....3.0 gr/bhp-hr Distillate-fuel units.....3.0 gr/bhp-hr Natural Gas / Dual fuel.....3.0 gr/bhp-hr

1) The compliance deadline for most sources is May 1, 2009. However, electric generating units have interim emission limits and extended compliance time frames. See Table 2.

1. Implemented on an annual basis

The proposed rule implements the RACT requirements on an annual basis. This is the default approach for RACT as reflected in the current EPA 8-hour ozone Phase II Implementation Rule (70 FR 71611). Controls implemented for ozone purposes are cost-effective to operate year-round and yield continual air quality benefits related to fine-particles, haze, acid rain, and eutrophication of lakes.

2. 30-day rolling average emission limit

The 30-day rolling averaging time is a short term, rate-based approach to ensure full benefit of the installed control equipment. In this way, emissions are continuously controlled in the event conditions are conducive to forming ozone. This approach allows averaging of the typical variations in controlled emission levels from a single unit.

3. Emission unit exceptions

Emission units which operate at very low levels during the ozone season are exempt from RACT requirements. The rule also exempts units with low emission rates from installing additional controls to meet the RACT emission limits.

4. Compliance monitoring and demonstration

The proposed rule requires most sources subject to emission limitations to demonstrate compliance using continuous emissions monitoring. For electric utility (EGU) sources this monitoring is based on 40 CFR part 75 methods and for industrial source monitoring is based on 40 CFR part 60 methods. For a few source categories with low variability in operations or emission rates, compliance is demonstrated by periodic stack testing. The proposed emission monitoring requirements are consistent with existing state and EPA programs. The rule will also allow a source to request approval of an alternative monitoring method.

5. Electric utility coal-fired boiler phased compliance schedule.

For electric utility coal-fired boilers the rule sets a phased compliance schedule with interim emission limits for May 1, 2009 and final RACT emission limits by May 1, 2013. The purpose of the phased compliance schedule is to allow the electric utilities the necessary time to install post combustion controls while maintaining a reliable electric supply. Some control technologies, like selective catalytic reduction equipment, can take up to two years to install for an individual project. This is compounded by the fact that utilities are subject to limited

installation windows which further restrict the installation schedule. On this basis, multiple installations cannot be fully accomplished on all electric utility boilers within the moderate nonattainment area by 2009. The phased approach is also consistent with operating generating units on a system-wide basis and utilization of a multi-facility averaging program.

The schedule of phased limitations is provided in Table 2. The interim emission limits for 2009 is based on implementation of full combustion modifications and a limited number of selective non-catalytic reduction installations. In this manner, the proposed rule sets forth a RACT level of NO_x control across electric utility boilers achieved on a schedule the Department has found to be as expeditious as practicable. Attachment B summarizes the expected emissions from electric utility coal fired boilers.

Table 2. Compliance Schedule for Electric Utility Coal-Fired Boilers

Compliance Date	**Emission Limits (lbs/mmbtu)**	
	Coal-fired Boilers > 1000 mmbtu/hr	**Coal-fired Boilers >500 and <1000 mmbtu/hr**
May 1, 2009	wall fired = 0.15 tangential fired = 0.15 cyclone = 0.15 fluidized bed = 0.15 arch fired = 0.18	wall fired = 0.20 tangential fired = 0.15 cyclone = 0.20 fluidized bed = 0.15 arch fired = 0.18
May 1, 2013	wall fired = 0.10 tangential fired = 0.10 cyclone = 0.10 fluidized bed = 0.10 arch fired = 0.18	wall fired = 0.17 tangential fired = 0.15 cyclone = 0.15 fluidized bed =0.10 arch fired = 0.18

6. Alternative compliance methods.
The proposed RACT rule provides several compliance options.

1) Emissions from one or more units subject to a RACT emission limitation may be averaged with other similar units at an industrial or small utility facility. Under this approach all similar units at the facility must be included in the averaging program. This is to eliminate a potential shift in generation/ production to unit not subject to the RACT requirements.

Emissions averaging applies the current applicable emission limit of each unit on a heat input weighted basis to determine an average facility or system emission limit. The EPA requires that averaging programs like the system averaging in the proposed rule have an additional emission reduction applied to the facility or system emission limit as an environmental benefit in lieu of the provided flexibility. (See *Improving Air Quality with Economic Incentive Programs*, EPA-452/R-01-001, Jan. 2001.) Under facility averaging the proposed environmental benefit is the implementation of an annual and ozone season mass cap.

2) Emissions units may participate in an emission averaging program across multiple units and facilities. Each unit can only participate in one type of averaging program on an annual basis (facility or system-wide). The proposed environmental benefit is

the EPA default of 10% reduction in the emission rate on an annual and an ozone season basis.

3) An individual source may request an alternative emission limitation or compliance schedule, with a determination made on a case-by-case basis by the Department. An alternative emission limit may be the result of an engineering assessment that demonstrates RACT controls are not economically or technically feasible for that unit. Any determination of an alternative limit or schedule must also account for a unit's ability to participate in either a facility or system-wide emissions averaging program.

7. Utility reliability waiver

The proposed rule contains a provision that allows an electric or steam utility or natural gas transmission facilities to request a waiver from an applicable emission limit for a period of time due to reliability issues. This provision acknowledges that these facilities serve non-interruptible customers and uncontrollable events may occur which result in an increase in emissions. Facilities generating steam for process and manufacturing purposes are not eligible for the waiver.

3. Hearing Summary and Comment Summary

A public hearing was held on March 15 in Milwaukee. Twelve people attended the hearing. WE Energies, Alliant Energy, and Wisconsin Manufacturers and Commerce, testified opposing major portions of the rule. Sierra Club/Clean Wisconsin testified in support of the rule, but suggested changes to strengthen the emission limits in the rule. Additionally, written public comments were accepted through March 19th, 2007. The Department received written comments from:

Alliant Energy
ANR Pipeline
David Bender
Engine Manufacturers Association
James McCarthy
Sierra Club/Clean Wisconsin
Solar Turbines
US EPA
Waste Management
WE Energies
Wisconsin Industrial Energy Group
Wisconsin Legislative Council Rules Clearinghouse
Wisconsin Paper Council
Wisconsin Manufacturers and Commerce

A list of comments and Department responses is found in Attachment C.

4. Impact to Existing Policy

This proposal is consistent with existing state statutory policy for ozone rules under s. 285.11(6), Wis. Stats., to revise and implement state implementation plans for the purpose of prevention, abatement and control of air pollution in Wisconsin.

5. Has the Board dealt with these issues before?

The Board authorized public hearings on this rule at its January, 2007 meeting. Most recently prior to that, the NRB adopted ch. NR 428 in 2000 for regulation of NO_x emissions from stationary sources in the state. Those regulations were formulated to meet rate-of-progress and attainment requirements for the 1-Hour Ozone Attainment Demonstration in Southeastern Wisconsin. That rule established performance standards for existing electric utility and larger industrial sources in the area now designated as moderate under the 8-Hour ozone standard. The sources subject to ch. NR 428 requirements are also subject to the proposed RACT rules. In some cases, meeting the NR 428 limits exempts units based on lowering their potential to emit below 100 tons per year.

6. What changes have been made to AM-17-05?

a. Combustion Tuning

The Department proposed that sources should participate in combustion tuning, since it provides energy and environmental benefits. However, the provisions of the proposed rule dealing with combustion tuning were controversial because they were viewed as overly prescriptive and requiring unnecessary recordkeeping. Considering the comments from the industrial sector in Wisconsin, the Department proposes to drop combustion tuning from the NOx RACT rule. This provision wouldn't have accounted for very large emission reductions because it would have applied to smaller sources and some of the reductions will be achieved through voluntary combustion tuning.

The Department may consider combustion tuning in future air quality related initiatives such as PM2.5 or ozone attainment demonstrations, reasonable progress for haze or climate change proposals. In these new initiatives, DNR will work with industrial representatives to address their concerns and streamline testing and reporting requirements.

b. Exemptions.

General Exemptions – For purposes of clarity and streamlining of requirements, additional exemptions were included to define emergency, auxiliary, and backup units which would normally qualify under the low operating unit exception. Exceptions were added based on the periodic or intermittent nature of operation for peaking or reliability units.

Low operating unit – The Department proposed the low operating unit exception based on a 5% ozone season capacity factor for reciprocating engines and combustion turbines and a 10% capacity factor for the remaining source categories. Based on comments concerning cost-effectiveness, the Department revised the capacity factor used in calculating the utilization threshold to 20% for all source categories.

Other regulated unit – The rule exempts emission units that have been well controlled under existing NR 428 requirements and for which cost rapidly increases in meeting additional reductions under the RACT requirements. An exemption threshold based on potential emissions of 50 tons per year was proposed in the public hearing draft of rule. Based on comments the Department increased the threshold to 75 tons per year in the revised rule.

c. Source Categories and Emission limits

Solid fuel wall-fired boilers – The proposed rule provided a distinction between low and high heat release wall fired boilers based on achievable emission limitations. The basis for the

distinction is being modified based on comments to reflect standard methods and terminology in the industry without affecting the applicability of the requirements.

Boilers – The exemption threshold for residual fuel-fired boilers was originally proposed at 60 mmBtu/hr and the Department revised the limit to 65 mmBtu/hr.

Process heating – Comments were received concerning the applicability threshold of 50 mmBtu/hr for all process heaters. The thresholds have been revised based on fuel type and cost-effectiveness. Similar to other categories, natural gas, distillate oil, and residual fuel emit NOx at increasingly higher emission rates in that respective order. Therefore it is appropriate to distinguish lower unit size thresholds for the higher emitting fuels. The revised thresholds are natural gas = 100 mmBtu/hr, distillate fuel = 100 mmBtu/hr, and residual fuel = 65 mmBtu/hr. To address comments related to the distinction of process heaters and other gaseous and liquid fuel fired units such as dryers and ovens, the Department clarified the definition of process heaters

Combustion turbines – After reviewing comments from industry and a turbine manufacturer, the Department adjusted source category thresholds and emission limits for combustion turbines. The Department created an exemption size threshold for simple cycle turbines at 25 MW. The Department also adjusted emission limits for all combustion turbine categories to reflect available low NOx combustion techniques without the use of post-combustion control.

Reciprocating engines – Based on comments concerning cost and technical issues, the Department raised exemption threshold for affected engines from 250 to 500 hp. Additionally, the Department revised the emission limits for natural gas fired engines to 3.0 gr/bhp-hr.

d. Monitoring requirements

Based on comments, the Department revised several monitoring requirements to streamline requirements without compromising the compliance demonstration.

The public hearing draft rule allowed an alternative EPA monitoring method with written approval of the department. The revised rule will allow this alternative without approval for specific source categories.

Other miscellaneous modifications have been made based on comments to address consistency in testing methods standard to certain source categories and clarification.

e. Green Tier

U.S. EPA commented that including the green tier provision in the draft rule would require that the green tier program be submitted to EPA for approval as part of a state implementation plan (SIP) revision. While the Department strongly supports the goals of the Green Tier program, we believe that the Green Tier program being a federally enforceable part of the SIP would delay promulgation of this rule and might be counter to the Green Tier program goals. Therefore, we've dropped the proposed Green Tier language in this rule that was only a general reference to the program anyway. The Department will continue to search for ways to take advantage of the Green Tier program to achieve superior environmental goals.

f. Steam and Electric Reliability Waiver

The reliability waiver establishes a process to address situations where facilities supplying electricity or steam for critical needs must continue to operate and exceed limitations due to uncontrollable or foreseeable events. The rule is revised to allow natural gas transmission facilities subject to reliability constraints by the Federal Regulatory and Energy Commission to access this provision.

g. Minor changes to address comments from Legislative Council Rules Clearinghouse and US EPA

The Department made the necessary changes for clarity and to meet rule writing requirements.

7. Who will be affected by the proposed rule? How will they be affected?

The rule provides a significant public health benefit for the citizens of the state. Using an EPA health benefits model, COBRA, the Department estimated, when fully implemented, the NOx RACT rule would provide about $80,000,000/year in public health benefits compared to compliance costs of about $16,000,000 annually.

The proposed rule affects emission units at major source facilities which have applicable emission limits specified in the rule. In the moderate nonattainment areas the affected emission units include electric utility generating units, industrial boilers, combustion turbines, glass and steel furnaces, asphalt plants, process heaters, and reciprocating engines. Refer to Attachment A for a summary of anticipated general control levels and range of cost-effectiveness represented by rule requirements.

The affected electric utility generating units consist primarily of 13 large coal fired boilers. The proposed rule is likely to result in significant post-combustion controls achieving 50% to 90% reduction from uncontrolled emissions for most of these units, at a cost effectiveness ranging from $1,000 to $2,200 per ton of controlled NO_x emissions. The rule also affects 3 coal-fired boilers which are smaller than typical electric generating units, but which are used for steam utility services. These boilers will require less intensive post-combustion controls, approximately a 50% reduction, at a cost-effectiveness of $2,500 per ton. All of these coal-fired boilers are eligible to participate in multi-facility trading allowing electric utilities maximum flexibility in meeting RACT requirements.

The remaining source categories are primarily gaseous and oil-fired combustion processes. The prevalent method of control applied to these types of emission units is combustion modification consisting of over-fire air and low NO_x burners. The Department expects combustion modifications to achieve a 30% to 60% reduction at individual sources burning gas and oil. The one exception is very large reciprocating engines, where it appears cost-effective controls may achieve an 80% - 90% reduction in emissions. The analysis of the rule identifies that up to 25 gaseous or oil fired emission units may have to take additional action to meet proposed RACT emission limits of the rule. This results in an estimated NO_x reduction of 46% from a base emission level at a cost effectiveness ranging from $300 to $2,500 per ton.

The RACT rule may also affect additional emission units in the future in two ways. First, emission units which currently operate at very low levels are currently exempt from the emission limitations. Once these units exceed a threshold utilization level they are subject to meeting the requirements. Secondly, the rule will affect any source which becomes a major source (PTE > 100 TPY) due to

adding additional sources or modifying existing sources for additional capacity. At that time, a source would have to review their sources for applicability to the RACT requirements. This aspect of the rule serves to maintain emissions at RACT controlled levels equitably across emission sources in the area.

8. What are other states doing?

States near Wisconsin with 8-hour ozone nonattainment areas are Illinois, Indiana, Michigan and Ohio. Illinois, Indiana and Ohio also have moderate non-attainment areas. All of the Michigan nonattainment areas are of a lower non-attainment designation of either "basic" or "marginal".

Illinois: The state of Illinois has proposed a statewide RACT rule for industrial boilers and other sources with a potential to emit of 100 tons per year or greater. The Illinois rule affects smaller sources and implements equivalent or more stringent requirements than those in the Wisconsin rule. The Illinois proposed RACT emission limits are based on a cost-effectiveness ranging up to $2,500 per ton of NO_x removed. The rule proposes combustion tuning for boilers between 50 and 100 mmbtu/hr and emission limits for units approximately equivalent to 50 mmbtu/hr across the source categories. Illinois EPA negotiated very stringent SO2 and NOx limitations with the utilities in Illinois that generate about 90% of the electric power in the state. The resulting emission limits for the Chicago area are more stringent than what the Department has proposed for NOx RACT in the Milwaukee area.

Indiana: Indiana is not proceeding with NOx RACT rule development at this time.

Michigan: The state of Michigan has made no determination regarding the need for developing RACT rules. A Michigan RACT rule is required only if attainment in the basic areas cannot be demonstrated by the state's SIP submittal deadline of June 2007.

Ohio: Ohio is developing NOx RACT rules for industrial sources in the Cleveland nonattainment area. The rule affects smaller sources and implements equivalent or more stringent requirements than the Wisconsin rule for industrial sources. The proposed Ohio rule considers controls up to $5,000 per ton of controlled NOx. The proposal requires combustion tuning for boilers between 20 and 50 mmBtu/hr. Emission units of approximately 50 mmbtu/hr and larger across source categories must meet emission limits.

9. Information on environmental analysis

An environmental analysis of the impact of the proposed rule revisions is not needed as these changes are considered to be a Type III action under s. NR 150.03(3), Wis. Adm. Code. A Type III action is one that normally does not have the potential to cause significant environmental effects, normally does not significantly affect energy usage and normally does not involve unresolved conflicts in the use of available resources.

10. Regulatory Flexibility Analysis

There are no emission or performance requirements or compliance and reporting requirements proposed for small businesses and as such are not anticipated to directly affect small businesses. The proposed RACT rules are applicable to major industrial entities and electric utility facilities.

Small business may experience electricity rate impacts related to RACT requirements for the electric generation sector. The cost of controls is estimated to be less than 1-3% of current electricity rates.

CORRESPONDENCE/MEMORANDUM

Attachment A.

DATE: April 4, 2007

TO: Larry Bruss

FROM: Tom Karman

SUBJECT: Technical Basis for RACT Determinations

This document provides the technical basis for proposing Reasonably Available Control Technology (RACT) requirements for NO_X emission units in Southeastern Wisconsin. The previous version of this document has been revised to incorporate new information that's been submitted or become available during the public comment process for the proposed RACT rule.

For several reasons it is necessary to perform an analysis of RACT requirements. In the mid-1990's, NO_x RACT programs were implemented by other states to meet requirements under 1-hour ozone non-attainment designations. However, because NO_x control technologies and costs have changed, we found it necessary to perform an up-to-date evaluation of RACT. And, although other state RACT rules are an important reference the associated supporting evaluations may not have addressed issues specific to emission units found in Wisconsin. Other states currently developing RACT rules are following a similar process of developing up-dated RACT requirements. The basis for RACT requirements is also a necessary component of submitting the proposed rule to EPA for approval as a SIP component.

Definition of RACT

The EPA defines RACT as "the lowest emission limitation that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility." (44 FR 53762, September 17, 1979.)

Evaluating RACT

According to the EPA definition, the determination of RACT is based on evaluating two primary criteria:

- A review of available control technologies and applicable emission reductions for each type of emissions unit.

- The cost-effectiveness, typically expressed in dollars per ton of controlled NO_x, of applying the control technologies.

We evaluated these two criteria following general approaches and methods established in EPA's 1994 series of Alternative Control Technology (ACT) documents for NO_x source categories. The ACT documents were the primary reference for states in developing the 1990 vintage RACT requirements. However, we updated the information on control technology and costs based on more recent EPA information, equipment vendor information, actual installations, and information received during the public comment period. In some cases, we used applicable cost-effectiveness directly from reference

resources utilizing the same or similar methodologies. All cost information is presented in 2000 or later dollars. We adjusted costs from historic documents based on the consumer price index.

The first step in the RACT evaluation process is to identify control technologies applicable to general emission source categories. Only those control technologies which are found to be readily available and have already been utilized in existing applications were used in the evaluation. The general types of control technology found applicable to controlling NOx emissions are shown in table A1.

Table A1. General NOx Controls Applied in the RACT Evaluation.

Category	Technology	Control Efficiency	Compliance Margin
Combustion Modifications	Combustion Tuning	5 – 35%	NA
	Combustion air staging: OFA, FGR	25% - 50	Gaseous & oil fired – 10%
	LNB	50 – 70%	Solid fuel fired – 15%
	CT Steam/water Injection	60% - 90%	10%
	Engine combustion modifications	30 – 90%	10%
Post Combustion	SNCR	35% - 60	20%
	SCR	75% - 90%	25%

To determine potential RACT controlled emission rates we applied the control efficiencies of applicable technologies to baseline emission rates as was done in the 1994 vintage RACT determinations. These baseline emission rates for most source categories are from the ACT documents and represent a typical uncontrolled source for that source category. However, we used historic actual emission rates in the case of EGU boilers and combustion turbines as there are a limited number of individual units and their emissions are well quantified. The definitions of acronyms used for the control technologies can be found at the end of the memo.

Also, for emission units which already have controls in place due to current state NOx requirements, we applied additional controls to the actual or the applicable emission limit (e.g. electric and industrial boilers, reciprocating engines,). This is a secondary test for the feasibility and cost of additional controls in meeting the proposed limits.

Unless specifically stated for a technology, we assumed the reported control efficiencies are based on long-term averages of control technology performance. Therefore, in accounting for potential operational variability in estimating the emission limit for compliance we applied a compliance margin factor, as shown in Table A1, in proposing the RACT emission limits. Based on published evaluations, the control variability for post combustion control can be significant and therefore the compliance margin is set higher than for combustion modifications.

To determine cost-effectiveness, we estimated the annual cost for each control technology and divided it by the amount of controlled NO_x emissions. The annual control cost consists of the total capital and installation costs annualized over the life of the equipment plus annual operating costs of the equipment. The cost-effectiveness is then calculated as the annualized cost divided by the calculated reduction in each case. We tested the cost-effectiveness over a range of capacity factors and emission unit sizes. This is necessary as technology capital cost is usually relatively higher for a small unit than for a larger unit (economies of scale) and operational cost will vary over utilization of each individual unit. For the large electric utility boilers costing is based on actual operation of the

existing units. The costing analysis of utility coal-fired boilers is presented in more detail in a separate section below.

The calculation of cost-effectives does not include the cost of compliance monitoring. The EPA references in discussing RACT cost-effectiveness (see discussion below) do not include the cost of compliance monitoring. This is a separate consideration in structuring rule requirements.

The determination of RACT is an iterative process where the evaluations of technology and cost-effectiveness further define sub-categories of emission units and applicable RACT requirements. For particular source categories the cost-effectiveness will define unit sizes and operational levels or capacity factors differentiating RACT requirements. We proposed the emission limits to reflect these considerations.

Cost-effectiveness Basis for RACT

For the evaluation, we assumed an upper limit of approximately $2,500 per ton of NOx controlled from uncontrolled emission rates in proposing NOx RACT emission limits. Other factors considered is where cost for additional control increase rapidly. This rate of increasing cost is evaluated versus the size and operational levels of the emission units and versus in evaluating incremental reductions for units subject to existing emission limits.

The basis for assuming $2,500 per ton considers several factors as outlined below.

In a 1994 memo, EPA indicated that RACT controls should, at a minimum, overlap the range of $160 to $1,300 per ton. The memo also states, in discussing controls for utility boilers, that controls meeting EPA's presumptive NOx RACT levels show a range in cost effectiveness of about $160 to $5,100 per ton of NOx (based on 1991$). These cost ranges are based on controls from uncontrolled emission rates. In the recent 8-hour ozone Phase II Implementation rule, EPA referenced the $160 to $1,300 range as still applicable in evaluating RACT. However there are several considerations that indicate other levels of cost-effectiveness may be more appropriate in the current determination of RACT.

- The $1,300 per ton cost-effectiveness from the 1994 is approximately $2,000 per ton in 2005 dollars using the consumer price index. The normal EPA methodology is to normalize costing to current dollars.

- The cost range referenced in EPA's 1994 memo was based on an analysis of controls available at that time. Since then, availability, control efficiencies, and cost of control equipment have changed. EPA's original evaluation referenced in the memo a cost range of $320 to $5,200 per ton for SCR installations at 80 to 90% reduction which is very similar to the cost range stated for other technologies. However, EPA did not feel that the knowledge based for SCR control was sufficient to assume it as technically and reasonably available for RACT at that time. The installation of SCR is now common practice as referenced in current EPA documents.

- EPA in their determination of NOx controls for the NOx SIP call determined $2,000 per ton to be "highly cost-effective". This cost was based on an average of controls predicted by a modeled trading program. The actual costs for the SIP program for individual units would be

higher and lower in than the average. Therefore assuming $2,500 per ton of NOx appears to be a reasonable ceiling in estimating applicable RACT controls.

- Other existing NO_x RACT programs are based on higher cost-effectiveness ceilings. Staff from the Northeast Ozone Transport Commission region indicates the average cost-effectiveness for already established NO_x RACT programs ranged upwards to $3,500 per ton. A recent determination of RACT for the Charleston, South Carolina identified RACT reductions up to $3,500 per ton. And in 1990, the California Air Resources Board determined that a range of $2,000 to $10,000 (1990$) for cost-effectiveness as the average rate for installation of NO_x controls.

- Current development of RACT rules are based on levels higher than the minimum range presented in EPA's 1994 memo. For example, the state of Illinois is using a cost-effectiveness of $2,500 per ton as a guideline in proposing RACT emission limits for industrial source categories. According to staff, Ohio is proposing RACT limits based on costs up to $5,000 per ton.

Recommended RACT Control Levels

Based on the methodology outlined above, we propose emission limits for emission units over specific size thresholds by fuel types to satisfy RACT requirements at major sources. And the emission limits are found cost-effective when units in a source category operate at a utilization level over 20% of the source categories capacity threshold operating at full load. The utilization threshold relates when controls are warranted versus actual emissions.

In addition, we propose that an emission unit currently meeting one of the current state NOx emission limits (NR 428.04 and 0.05, excluding combustion optimization) be exempt from additional control in meeting the proposed RACT limits if the unit's emission potential is below 75 tons per year. This emission level identifies where additional controls would be cost-effective in meeting RACT limits based in context of parameters discussed for this evaluation. The units above the 75 ton threshold in Southeast Wisconsin include coal-fired utility boilers, large engines over 1000 hp and potentially residual fuel fired emission units.

The emission limits are listed in detail for each source category in Table A2 along with an assumed control technology. This does not represent the full spectrum of technologies that are available in many cases to achieve the equivalent control. The results from the specific application of evaluated control technologies and assumptions for existing coal-fired boilers in Wisconsin are presented in a separate section below.

I found combustion tuning to be an integral first step in reducing NOx emission for all for emission units equal to or greater than 50 mmBtu/hr in fuel consumption capability. Across the source categories the costs of combustion tuning for these units is largely offset by fuel savings. Below this level, combustion tuning may also be beneficial, but there was less information for all source categories (7). However, tuning is usually an integral portion of implementing combustion controls and there is not sufficient information available to determine the extent of tuning already occurring at Wisconsin sources. Also, the implementation approaches required across the different types of emission sources which capture the benefit of tuning requires further investigation. Therefore, since combustion tuning may already be occurring on a wide-spread basis and that specific requirements

need further investigation there may not be sufficient basis to include in the RACT requirements at this time.

Table A2. Summary of RACT Source Categories and RACT Controls

Source Category		Base Emission Rate (lbs/ mmBtu)	Control Technology and Efficiency	Control Ref.	RACT Emission Limit (lbs/ mmBtu/hr)	Cost-Effectiveness ($/ton)	Cost Ref.	Comment
Wall-fired boilers	> 1000 mmBtu/hr	0.46	SCR – 86%	1, 2, 3	0.10	1,300 – 1,600	2, 5	
	500 - 1000 mmBtu/hr – HHR	0.47	LNB – 40% +OFA- 25% +SNCR - 35%	2, 4	0.17	1,300 – 1,400	2	SNCR control adjusted for HHR.
	500 - 1000 mmBtu/hr – LHH	0.46	LNB – 40% +OFA- 25% +SNCR - 40%	2, 4	0.15	1,300 – 1,400	2	
	< 500 mmBtu - HHR	0.47	LNB – 40% +OFA- 25% +SNCR - 35%	2, 4	0.17	1,800 – 2,100	6	SNCR control adjusted for HHR.
	< 500 mmBtu - LHR	0.46	LNB – 40% +OFA- 25% +SNCR - 40%	2, 4	0.15	1,800 – 2,100	6	Cost is for 250 - 100 mmBtu/hr boilers @ 50% c.f.
Tangential-fired boilers	> 1000 mmBtu/hr	0.46	SCR – 86%	1, 2, 3	0.10	1,200 – 1,900	2	
	< 1000 mmBtu/hr	0.46	LNB – 40% +OFA- 25% +SNCR - 40%	2, 4	0.15	1,500 – 2,100	2,6	Cost is for 1000 - 100 mmBtu/hr boilers @ 50% c.f.
Cyclone-fired boilers	> 1000 mmBtu/hr	0.79	OFA – 50% +SCR – 89%	1, 2, 3	0.10	700 -1,200	2	assumed PC boiler OFA cost
	< 1000 mmBtu/hr	0.86	OFA – 50% +SCR – 75%	1, 2, 3	0.15	1,700 – 2,100	2, 5	Low cost represents Edge 3 from ref. 2. High cost is derived from ref. 6 for 100mmBtu/hr boiler @ 50% c.f.
Arch-fired boilers	all capacity sizes	0.24	Tertiary Air – 20%	3	0.18	1,200 – 1,500	2	Reported average emission rate
Fluidized bed boilers	all capacity sizes	0.15	SNCR – 50 to 60%	4,6,7	0.10		6	
Stoker fired boilers	≥ 250 mmBtu/hr	0.50	OFA – 25% + SNCR – 50 to 60%	4,6,7	0.20	<2,500	6	
	< 250 mmBtu/hr	0.50	SNCR – 50 to 60%	4,6,7	0.25	<2,500	6	

Table A2. Summary of RACT Source Categories and RACT Controls (continued)

Source Category		Base Emission Rate (lbs/mmBtu)	Control Technology and Efficiency	Control Ref.	RACT Emission Limit (lbs/ mmBtu/hr)	Cost-Effectiveness ($/ton)	Cost Ref.	Comment
Gas fired boilers	> 100 – 150 mmBtu/hr	0.22	LNB/OFA/GR – 60%	6, 14	0.08	700 – 2,200	6	Cost range for 80% & 25% C.F., respectively
Distillate oil fired boilers	> 100 mmBtu/hr	0.21	LNB/OFA/GR – 50%	6, 14	0.10	700 - 2,300	6	Cost for 100 mmBtu/hr boiler @ 25% C.F.
Residual oil fired boilers	> 65 mmBtu/hr	0.38	LNB/OFA/GR – 50%	6, 14	0.15	700 – 2,400		Cost for 50 mmBtu/hr boiler @ 25% C.F.
Gas fired process heater	> 100 mmBtu/hr	0.26	LNB – 60%	7, 14	0.10	<2,300	6	Cost for 50 mmBtu/hr @ 25% C.F.
Distillate oil process heater	> 75 mmBtu/hr	0.32	LNB/GR – 60 - 70%	7, 14	0.12	<2,500	6	Cost for 50 mmBtu/hr @ 25% C.F.
Residual oil process heater	> 50 mmBtu/hr	0.54	LNB/GR 60 – 80%	7, 14	0.18	< 1,500	6	Cost for 50 mmBtu/hr @ 25% C.F.
Other process heating devices				14				Same cost basis as for boilers. Operate at high capacity factors
Metal Furnaces	> 100 mmBtu/hr	0.22	LNB/OFA/GR – 60%	6	0.08	700 – 2,200	6	Assume cost for NG Boilers. Operate at high capacity factors

Table A2. Summary of RACT Source Categories and RACT Controls (continued)

Source Category		Base Emission Rate (gr/bhp-hr)	Control Technology and Efficiency	Control Ref.	RACT Emission Limit (gr/bhp-hr)	Cost-Effectiveness ($/ton)	Cost Ref.	Comment
Reciprocating Engines > 500 hp	Rich-burn	16.4	NSCR – 80 – 90%	9, 14	3.0	< 2,500	9	Cost for 500 hp unit @ 20% C.F.
	Lean-burn	18.6	LEC – 80 - 90%	9, 14	3.0	< 2,500	9	Cost for 500 hp unit @ 20% C.F.
	Distillate compression	13	SCR – 80 – 90%	9, 14	3.0	< 2,500	9, 7	Cost for 500 hp unit @ 20% C.F.
	Dual fuel compression	10.7	LEC – 80 - 90%	9, 14	3.0	< 2,500	9	Cost for 500 hp unit @ 20% C.F.
	Biogas fired	1.8	NA	14	3.0	NA		Inherently low emitting

Source Category		Base Emission Rate (ppm @ 15% O2)	Control Technology and Efficiency	Control Ref.	RACT Emission Limit (ppm @ 15% O2)	Cost-Effectiveness ($/ton)	Cost Ref.	Comment
Simple CTs > 50 MW	Distillate Oil	200	Steam/ Water Inj. – 60 - 70%	7, 14	65	< 2,500	7	Interpolated cost-effectiveness for 25 and 100 MW units @ 25% C.F.
	Natural Gas	99 – 430	DLN - 90%+	7, 14	25	< 1,300	7	Cost-effectiveness for 25 MW unit @ 25% CF
Simple CTs 25 - 50 MW	Distillate Oil	200	Steam/Water Inj. – 50 - 60%	7, 14	110	< 2,100	7	Cost-effectiveness for 25 MW unit @ 25% C.F.
	Natural Gas	99 – 430	DLN – 80 - 90%	7, 14	42	< 1,300	7	
Combined Cycle CT > 10 MW	Distillate Oil	200	Steam/Water Inj. - 60 - 80%	7, 14	42	< 2,500	7	Interpolated cost-effectiveness for 5 and 25 MW units @ 90% C.F.
	Natural Gas	99 – 430	DLN 80- 90%	7, 10	< 25 MW = 42 > 25 MW = 9	< 2,500	7	
Biogas fired combustion turbines	Biogas	25 – 35	NA	10, 14	35			Inherently low emitting

Table A2. Summary of RACT Source Categories and RACT Controls (continued)

Source Category		Base Emission Rate	Control Technology and Efficiency	Control Ref.	RACT Emission Limit	Cost-Effectiveness ($/ton)	Cost Ref.	Comment
Glass Furnace	> 50 mmBtu/hr	10 lbs/ton of glass	Oxy-firing	7	2.0 lbs/ ton of glass	<2,500	7	Oxy-firing during rebuild can pay for itself.
Lime Kiln > 50 mmBtu/hr	Natural Gas	U.D.	LNB	10	0.10	700 – 2,200	7	- Assume same cost as boilers for NG, DO, RO.
	distillate oil	U.D.		10	0.12 lbs/mmBtu	< 2,300	7	
	residual oil	U.D.		10	0.15 lbs/mmBtu	< 1,600	7	
	coal	U.D.	mid-kiln firing	10	0.60 lbs/mmBtu	< 1,000	7	-Controls based on WDNR BACT analysis. -Cost based on cement plants
	coke	U.D.		11	0.70 lbs/mmBtu		7	
Asphalt Plants > 65 mmBtu/hr	Natural Gas	0.26	LNB – 50%	10	0.15 lbs/mmBtu	<2,300	7	assume same as process heater costs. Asphalt plants fire multiple fuels
	distillate oil	0.32	LNB – 50%	10	0.20 lbs/mmBtu	<2,500	7	
	residual oil	0.54	LNB – 50%	10	0.27 lbs/mmBtu	< 1,500	7	

U.D - undetermined

Evaluation of Coal-fired Boilers

Large coal-fired boilers represent more than 90% of the stationary source NO_x emission in Southeastern Wisconsin. These boilers include 13 very large units used for electricity generation and 3 smaller units used to generate steam for industrial processes or space conditioning.

In the RACT evaluation for these boilers, we considered the following control technologies:

- Over-fire Air
- Low NOx Burners
- Selective Non-Catalytic Reduction (SNCR)
- Selective Catalytic Reduction (SCR)

I evaluated these control technologies singularly and in various combinations. There are also a number of factors which affected the application and effectiveness of these technologies to the coal boilers including unit size, fuel type and firing configuration. The technologies and control assumptions evaluated for each type of boiler is illustrated in Table A5.

For boilers greater than 500 mmBtu/hr, we used, control costs and control effectiveness from EPA's base data used for running the Integrated Planning Model (1). However, this size class of boilers in Wisconsin is comprised totally of electric utility boilers which in some case have already implemented the same or similar controls to those being evaluated. Therefore, where available, we incorporated information for cost submitted to the Public Service Commission in certificates of authorization and effective emission rates reported to the department. In cases where there is a significant difference, uncontrolled emission rates are included for both the general category and for the specific unit based on historic reported rates.

For boilers less than 500 mmBtu/hr, the application of technology is based primarily on EPA's recent compilation of control options for industrial boilers (6). Other sources were utilized as reference in applying the control information (4) (7).

Along with the average cost of control from an uncontrolled basis, we calculated the marginal cost of control for each option. This demonstrates the relationship of combining technologies as well as testing the incremental cost for emission units with existing controls. The incremental or marginal cost of installing additional control did not appear excessive for any option where the average cost of total control was less than the $2,500 per ton ceiling.

Table A5. Summary of the Evaluation of Control Technologies for Wisconsin Specific and Typical Source Category Coal-Fired Boilers.

						Control Technology Evaluations								
Boiler Size Class (mmBtu/hr)	Firing Configuration	Facility	Unit	Firing Capacity (mmBtu/hr)	Mega-watts	Base Emission Scenario	Base Emission Rate (lbs/ mmbtu)	Technology	Control Efficiency	Annual Cost ($M)	Controlled Emission Rate (lbs/ mmBtu)	Controlled Emission Rate w/ C.M. (1)	Cost of Measure ($/ton) (2)	Average Cost of Control ($/ton) (3)
> 1000	wall-fired	Pleasant Prairie	1	6,158	580	AU	0.46	*SCR	85%	14,695,949	0.07	0.09	1,605	1,605
> 1000	wall-fired	Pleasant Prairie	2	6,158	580	AU	0.46	*SCR	85%	12,710,697	0.07	0.09	1,364	1,364
> 1000	arch-fired	South Oak Creek	5	2,298	258	AU	0.24	*Tertiary Air	25%	525,076	0.18	0.18	1,106	1,106
						AU + tertiary air	0.18	SCR	61%	4,689,040	0.07	0.09	5,386	3,876
> 1000	arch-fired	South Oak Creek	6	2,283	260	AU	0.23	Tertiary Air	20%	531,528	0.18	0.18	1,502	1,502
						AU + tertiary air	0.18	SCR	61%	4,772,827	0.07	0.09	5,517	3,464
> 1000	tangential	Edgewater	5	4,366	380	AU	0.22	LNC3	40%	929,753	0.13	0.13	749	749
						AU + LNC3	0.13	SNCR	35%	3,248,796	0.08	0.10	5,002	2,209
						AU + LNC3	0.13	SCR	46%	7,279,567	0.07	0.09	2,765	2,833
						CU	0.46	SCR	85%	7,279,567	0.07	0.09	1,500	1,913
> 1000	tangential	South Oak Creek	7 / 8	2,608	280	AU	0.39	*LNC2	64%	912,749	0.14	0.14	327	327
						AU	0.39	SCR	82%	5,381,213	0.07	0.09	1,506	1,506
						AU + LNC2	0.14	SNCR	35%	2,420,571	0.09	0.11	4,411	999
						CU	0.46	SCR	85%	5,381,213	0.07	0.09	1,232	1,232
> 1000	cyclone	Edgewater	4	3,529	330	AU	0.79	*OFA + SB	67%	2,533,848	0.26	0.26	461	461
						AU	0.79	SCR	90%	6,102,790	0.08	0.10	827	671
						AU + OFA + SB	0.26	SCR	73%	6,102,790	0.07	0.09	3,095	1,156
500 - 1000	wall-fired (HHR)	Valley	1 - 4	846	64	AU	0.47	*LNB	23%	283,705	0.36	0.36	1,169	1,169
						AU	0.47	LNB + upgrade	40%	317,490	0.28	0.32	782	782
						AU + LNB w/ upgrade	0.28	OFA	26%	113,816	0.21	0.24	748	773
						AU + LNB w/ upgrade	0.28	SNCR	36%	576,763	0.18	0.22	2,550	1,379
						AU + LNB w/ upgrade	0.28	OFA + SNCR	52%	690,579	0.13	0.16	2,213	1,404
500 - 1000	cyclone	Edgewater	3	844	60	AU	0.79	*OFA / SB	62%	1,044,356	0.30	0.30	834	834
						AU + OFA	0.30	SNCR	40%	878,133	0.18	0.22	2,841	1,232
						AU + OFA	0.30	SCR	75%	2,061,858.81	0.08	0.09	3,558	1,696
						CU	0.86	OFA	50%	1,044,355.59	0.43	0.49	943	943
						CU + OFA	0.43	SNCR	40%	662,400.00	0.26	0.31	1,982	2,308
						CU + OFA	0.43	SCR	75%	2,061,858.81	0.11	0.13	2,482	1,603
< 250 mmBtu/h	stoker	Milwaukee County	1 - 3	140		AU + OFA	0.45	SNCR - Urea	60%	see note (4)	0.18	0.22	2,384	2,384
						CU	0.53	SNCR - Urea	60%	see note (4)	0.21	0.25	2,384	2,384

Base Emission Scenario – This is the emission basis for applying control technologies. AU = actual uncontrolled emissions of the unit based on historic data. CU = a typical uncontrolled emission rate for emission units in that source category.

Technology definitions – OFA = overfire air, LNB = low NOx burners, LNC = low NOx burners with coupled overfire air, SB = smart burn (patented optimization process), SNCR = selective non-catalytic reduction, SCR = selective catalytic reduction

* These are existing controls with demonstrated control efficiency and emission rates.

The shaded areas illustrate a technology that was not considered to be cost-effective for the RACT determination.
1) C.M. is the compliance margin account for variability of controls in meeting an emission limit. The emission rate with CM is the actual demonstrated emission rate. For added controls the assumed CM is: 15% for combustion controls, 20% for SNCR, 25% for SCR.
2) This represents the cost-effectiveness of the measure incremental to the base emission scenario controls.
3) This represents the cost-effectiveness of all measures included in the base emission scenario and the additionally applied measure versus the actual or categorical uncontrolled emission rate.
4) The cost-effectiveness of the measure is that estimated by EPA for a coal fired boiler operating at 50% capacity converted to 2004$ (6)

Impact to Wisconsin Sources

The impact of the proposed RACT requirements in Southeast Wisconsin is summarized by general levels of control effort in Table A3 and by specific source category in Table A4.

The affected sources are identified and impacts calculated based on existing emission limitations in 2005 applied to historic operating levels or the unit's 2002 air emissions. We calculated the emission reductions by applying the proposed RACT emission limit or representative control efficiency. For asphalt plants, reciprocating engines, process heater, and metal furnaces, source categories units are screened by comparing reported emissions to the potential emissions of an uncontrolled source.

The RACT emission limitations represent a 30% to 90% reduction (from uncontrolled emission rates) with an estimated cost-effectiveness ranging from $500 to $2,500 per ton of reduction. The emission limitations represent an estimated reduction of approximately 14,919 tons per year of from the estimated base NOx emission levels.

Table A3. Proposed RACT Control Levels, Cost Effectiveness, and Estimated Wisconsin Source Reductions.

Control Categories (1)	Base NO_x Emissions (tons/year) (2)	Reduction from uncontrolled emission rates (3)	Estimated RACT Cost-Effectiveness ($/ton) (4)	Estimated NOx Reduction w/ RACT Limits (tons/year)
EGU coal fired boilers (5)	26,864 tpy (13 units)	50 - 90% Comb. Mods, SNCR, SCR	1,000 – 2,200	14,277 tpy (47% reduction)
Coal fired boilers < 500 mmBtu/hr	277 tpy (3 units)	50% Comb. Mods, SNCR	2,000 – 2,500	138 tpy (50% reduction)
Gas and oil fired source categories (gas and oil fired)[b]	1,138 tpy (60/25 units) (5)	30 - 90% Comb. Mods. / NSCR	300 – 2,500	504tpy (44% reduction)
Total	28,279 tpy (41 units)		300 - 2500	14,919 (53%)

1) Solid fuel boilers greater than 500 mmBtu/hr are large electric utility coal-fired boilers. Solid fuel boilers smaller than 500 mmBtu/hr include smaller electric utility and industrial sized solid fuel boilers. "Other Source Categories" include gas and oil boilers, combustion turbines, furnaces, asphalt plants, lime kilns, reciprocating engines, and heating processes.
2) EGU coal boiler emissions represent 2005 ozone season emission rates multiplied by an average of the highest 3 years of heat input for each unit between 2000 and 2004. Coal boiler < 500 mmBtu/hr and gas and oil fired source category emissions are based on 2002 primary combusted fuels, ozone season utilization levels, and emissions adjusted for NR 428 emission limits which became effective in 2003.
3) Percent reductions are from an uncontrolled basis. Combustion modifications = overfire air and low NO_x burners. SCR = Selective catalytic reduction. SNCR = Selective non-catalytic reduction.
4) The presented cost-effectiveness represents the calculated "average" cost of reduction from an uncontrolled or initial emissions level as defined for each source category.
5) 60 units equals total number in source categories / 26 units equals number of units expected to subject to emission limits and require additional control.

Note: The estimate of affected units and emissions is based on emission units estimated to be in a RACT source category. The actual number of affected units in the "Others Source Categories" is expected to be lower due to units being at facilities with a PTE < 100 TPY or being classified as low operating units.

Table A4. Estimated Impact of RACT applied to Wisconsin Sources.

RACT Source Category	Sources in RACT Category (1)			Impact of RACT Requirements			Proposed RACT Control	
	No. of Units	Est. NOx Emissions (tons) (2)	Emission Intensity (tons/unit)	No. of units adding controls under RACT (3)	Est. NOx reduction from Base emissions (tons)	Percent reduction from Base emissions	RACT Control Technologies	Estimated Control Cost from Uncontrolled Levels ($/ton) 2004$
Source Categories subject to Emission Limits:								
Solid Fuel Boilers > 1000 mmbtu/hr	8	22,685	2,836	8	12,354	54%	SCR, CM + SNCR	1,000 - 2,200
Solid Fuel Boilers > 500 mmbtu/hr	5	4,179	836	5	1,923	46%	C.M. + SNCR	1,000 - 2,000
Solid Fuel Boilers > 250 mmbtu/hr	0						C.M. + SNCR	
Solid Fuel Boilers < 250 mmbtu/hr	3	277	92	3	138	50%	C.M. + SNCR	2,200 - 2,500
Gaseous and Oil Boilers	16	131	8	0	0	0%	LNB, LNB + GR	800 - 2,500
EGU Combustion Turbines	9	262	29	4	74	28%	DLNB, S.I.+ W.I.	2000 - 2500
Industrial Combustion Turbines	6	75	13	2	63	84%	DLNB	1,500 - 2,500
Lime Kilns	0						C.M.	1,500 - 2,000
Glass Furnaces (4)	2	97	49	0	0	0%	Oxy-Fire	< 2,500 (a)
Furnaces	5	135	27	5	81	60%	LNB	500 - 1,500
Asphalt Plants (5)	7	65	9	0	0	0%	LNB	800 - 2,500
Process Heating	3	107	36	3	64	60%	LNB	800 - 2,500
Reciprocating Engines	12	266	22	11	222	83%	LEC, NSCR,SCR	< 2,000
Total for Units Affected by Emission L:imits	**76**	**28,279**		**41**	**14,919**	**53%**		

Notes:

1) No. of units reflect total number of units in the identified RACT source category regardless of major source status and not considering exemptions.

2) EGU coal boiler emissions represent emission rates in 2005 in meeting current NR 428 requirements and an average heat input. Industrial emissions represent 2002 emissions adjust according to NR 428 emission limitations effective in 2005.

3) Emission units which are not expected to meet exemptions which do not already controled to the RACT emission limit level.

4) Glass Furnaces emitted over 700 tons per year prior to 2001. However, St. Gobain converted to oxy-fire to upgrade furnaces and reduce fuel cost by 2005. The RACT limit is consistent with oxy-fire operation.

5) The owners and operators of most asphalt plants are entering into a general permit which restricts the facility PTE to less than 25 TPY.

a) Oxy-firing is a significant rebuilding which extends plant life. Cost attributable to NOx reduction < 2,000. (7)

References

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13) United States Environmental Protection Agency, Office of Air and Radiation. March 1994, *Alternative Control Techniques Document – NOx Emissions from Industrial/Commercial/Institutional (ICI)Boilers*, EPA 452/R-94-022.

14) Public comments received on the proposed RACT emission limits. WDNR, Bureau of Air Management, March 19, 2007.

List of Acronyms

- CM, Comb. Mod. – combustion modification
- DLNB – dry low NOx burner
- OFA – overfire air
- GR – gas recirculation
- LEA – low excess air
- LEC – low emission combustion
- LNC2, 3 – low NOx concentric firing
- LNB – low NOx burner
- Oxy-firing – processed oxygen used for combustion in place of air
- SI – steam injection
- SCR – selective catalytic reduction
- SNCR – selective non-catalytic reduction
- WI – water injection
- HHR – High Heat Release
- LHR – Low Heat Release

Attachment B. Analysis of Electric Utility NOx Emissions under the proposed CAIR and RACT rules.

Facility	Unit ID	Heat Input -- Ave of top 3, 2000-2004	NOx Emissions by Program and Compliance Year				
			2009		2012		2015
			(a) CAIR I Allocations (2009 - 2014)	EGU RACT Limits	EGU RACT Limits	RACT Emissions Averaging (Less 10%)	(b) CAIR II Estimated Allocations
Pleasant Prairie	1	48,186,350	3,528	3,614	2,409	2,168	3,012
Pleasant Prairie	2	49,036,435	3,578	3,678	2,452	2,207	3,065
South Oak Creek	5	15,827,661	1,173	1,424	1,424	1,282	989
South Oak Creek	6	15,728,881	1,200	1,416	1,416	1,274	983
South Oak Creek	7	22,396,506	1,618	1,680	1,120	1,008	1,400
South Oak Creek	8	21,363,295	1,630	1,602	1,068	961	1,335
Valley	1	4,412,992	224	441	331	298	276
Valley	2	4,279,358	224	428	321	289	267
Valley	3	4,718,643	224	472	354	319	295
Valley	4	4,664,807	224	466	350	315	292
Edgewater	3	5,151,457	338	515	386	348	322
Edgewater	4	20,756,100	1,576	1,557	1,038	934	1,297
Edgewater	5	28,547,851	2,136	2,141	1,427	1,285	1,784

Total Emissions (tons) ===>	**17,673**	**19,434**	**14,096**	**12,687**	**15,317**
Reduction Below CAIR I (tons) ===>		(1,761)	3,577	4,986	
Reduction Below CAIR II (tons) ==>		(4,117)	1,220	2,630	

Total Emissions less 15% compliance margin for meeting RACT emission limit (c) (tons) ===>	**17,673**	**16,519**	**11,982**	**10,784**	**22,585**

a) The first phase CAIR allocations are those contained in the proposed rule Board Order AM-03-06.

b) The CAIR allocations are determined on an ongoing basis after 2014. The allocations are estimated here by EPA's analysis indicated a program-wide emission rate of ~ 0.125 lbs/mmbtu.

c) A compliance margin is applied to meeting only an emission limit in estimating actual emissions. Under the CAIR program allocations may be purchased to address a shortfall in emission allocations.

Attachment C

Summary of Public Comments and Department Responses

The Natural Resource Board approved the draft RACT rule for public hearing and comments at its January, 2007 Board meeting. A public hearing was on March 15, 2007 in Milwaukee. Twelve people attended the hearing. WE Energies, Alliant Energy, and Wisconsin Manufacturers and Commerce, testified opposing major portions of the rule. Sierra Club/Clean Wisconsin testified in support of the rule, but suggested changes to strengthen the emission limits in the rule. Additionally, written public comments were accepted through March 19th, 2007. The Department received 14 sets of written comments. This document summarizes the public comments and the Department's responses to comments.

1. Implementation of the Clean Air Interstate Rule Satisfies the NOx RACT Requirement.

Comments:

WMC, WE Energies, and Alliant indicated that implementation of the Clean Air Interstate Rules for EGUs was enough to satisfy the NOx RACT requirement. The commentors quoted several EPA documents making a similar statement.

Response:

The Department disagrees with this position for the following reasons.

- The NOx RACT requirement and the CAIR program are developed to address 2 distinct provisions of the Clean Air Act. NOx RACT is a direct requirement of the §§ 172(c) and 182(b)(1)(A) and (2) and (f) of the Act [42 USC 7502(c) and 7511a(b)(1)(A) and (2) and (f)] which require that major sources of NOx (and VOCs) in ozone nonattainment areas be subject to emission limits that represent Reasonably Available Control Technology (RACT) . CAIR is an EPA program developed by federal rule to assist states in meeting the SIP requirements of § 110(a)(2)(D) of the Act [42 USC 7410(a)(2)(D)]. That provision requires a state SIP to include provisions prohibiting emission sources in the state from interfering with another state's ability to attain and maintain ambient air quality standards.
- EPA issued its conclusion that CAIR=RACT for electric generating units (EGUs), as part of EPA guidance for implementation of the 8-hour ozone standard ("Phase 2" of the Final Rule to Implement the 8-Hour Ozone National Ambient Air Quality Standard) in November 2005 (70 Federal Register 61611, November 29, 2005). EPA subsequently requested additional public comment of its CAIR=RACT conclusion in December, 2006 (71 Federal Register 75902, December 19, 2006). EPA has not yet responded to the additional public comments on its conclusion that CAIR=RACT for EGUs.
- EPA's Phase 2 guidance allows, but does not require, states to conclude those EGUs subject to and complying with CAIR meet NOx RACT requirements for EGUs.
- EPA's conclusion that CAIR=RACT for EGUs is based on EPA's analysis that the application of the CAIR NOx budget in the 28-state region in the eastern part of the country will result in more emission reductions in that region than the reductions accomplished by applying NOx RACT to those EGUs located just in the nonattainment areas in the same region.
- The CAIR rules are based on establishing a NOx emissions budget for each state calculated by allocating NOx emission allowances for EGUs within the state. The focus of the CAIR rules is a regional cap and trade program which allows an EGU to meet its CAIR emissions cap by installing controls or by purchasing allowances from another EGU within the 28-state region that has over complies with its emissions cap. Under the CAIR program, there is no assurance that a specific EGU will install NOx controls to comply with its emissions cap. Instead, an EGU could achieve compliance with CAIR through the purchase of allowances from an over complying EGU.
- EPA's guidance does not address the issue of how its conclusion that CAIR=RACT for EGUs complies with (or overrides) the specific Clean Air Act requirement that a state's SIP require NOx RACT emission limits for all major sources within an ozone nonattainment area. Federal courts have repeatedly held that EPA's guidance

cannot override a specific CAA requirement. For example, on December 22, 2006, the D.C. Circuit Court of Appeals vacated EPA's April 2004 rule ("Final Phase 1 Rule to Implement the 8-Hour Ozone National Ambient Air Quality Standard") because of the Court's finding that provisions of the rule were contrary to the anti-backsliding provision (§ 172(e)) [42 USC 7502(e)]of the Clean Air Act. *South Coast Air Quality Management District v. EPA*, 472 F.3d 882 (D.C. Cir. 2006).

- Because EPA's conclusion that CAIR=RACT for EGUs is not consistent with a specific Clean Air Act requirement (i.e., that all major sources of NOx emissions in an ozone nonattainment area are subject to NOx RACT), a state's reliance on EPA's conclusion could subject the state's SIP to a legal challenge.

For these reasons, the Department has included NOx RACT emission limits for <u>all</u> major NOx sources, including EGUs, in the ozone nonattainment areas in the proposed rule, in compliance with the Clean Air Act requirements for ozone SIPs. In addition, the Department has included a specific provision in the proposed NOx RACT rule which allows an EGU to demonstrate that the emission reductions that the EGU achieves in complying with the CAIR requirements constitute compliance with the NOx RACT emission limitation requirements of the proposed rule.

Specifically, section NR 428.26(2) of the proposed rule provides:

> "CAIR EMISSIONS UNITS. The owner or operator of an emission unit which is subject to the emission reduction requirements of the clean air interstate rule (CAIR) under 40 CFR part 97 may demonstrate that the NOX emission reductions achieved by the emissions unit in complying with the CAIR requirements constitute compliance with the NOx RACT emission limitation requirements of this subchapter."

This provision balances the specific requirement of the Clean Air Act to set NOx RACT emission limits for all major NOx sources in an ozone nonattainment area with the recognition that individual EGUs may meet both their CAIR requirements and their NOx RACT requirements through the installation of NOx emission controls which are designed and operated to meet both regulatory requirements. This provision contrasts with the opportunity provided by EPA guidance that allows states to rely on EPA's "generic" finding that CAIR=RACT for EGUs, an option which is in direct contradiction of the Clean Air Act requirement that NOx RACT be applied to all major sources in an ozone nonattainment area..

2. <u>Cost for RACT Controls.</u>

Comments:

Alliant, WIEG, WMC commented that DNR's $2,500/ton upper limit for RACT controls was too high. The commentors cite a 1994 EPA document that they claim establishes a $1,300/ton limit on the application of NOx RACT. They cite additional documentation included in EPA guidance, including the Phase 2 Implementation plan for the 8-hour ozone standard and the NOx SIP Call. WMC further claims that the DNR's application of the consumer price index to adjust to current year dollars is inaccurate. WMC claims that calculation of the maximum control costs should be based on the incremental costs and not calculated from an uncontrolled level.

ANR Pipeline indicates, "The costs and stringency associated with compliance approaches that may be appropriate for electric generating units (EGUs) are not appropriate for smaller industrial facilities…[B]ased on ANR's experience, requirements related to issues such as applicability thresholds, emission limits, and compliance monitoring and testing are more stringent and costly for the Proposed Rule than typical NOx RACT rules or EPA's NOx SIP Call." ANR also indicates that the control costs are underestimated.

Clean Wisconsin and Sierra Club commented that the $2,500/ton limit is too low. They cite data from other states where RACT was established in other states including the Ozone Transport Commission, South Carolina and California. In these states NOx control was found reasonable in ranges at $3,500/ton to as much as $10,000 in California.

Response:

DNR reviewed the comments and affirms its original analysis and determination that an upper limit of RACT should be calculated from a level of $2,500/ton based on reductions from an uncontrolled level. The basis for EPA's 1994

document is even older documents that are quite dated. The technology of NOx control and costs has change considerably since then. DNR believes that the strongest argument for establishing a $2,500/ton limit is EPA's NOx SIP Call. Quoting from EPA's NOx SIP Call rule: "The NOx controls for this rulemaking were considered highly cost effective for the purposes of reducing ozone transport to the extent they achieve the greatest feasible emissions reduction but still cost no more than $2,000 per ton of ozone season NOx emissions removed (in 1990 dollars), on average, for each subcategory." DNR believes that if EPA determined that $2,000/ton was highly cost effective that DNR could reasonably determine that $2,500/ton meets the reasonable test for NOx RACT in Wisconsin.

3. Intra-Facility and Multi-Facility Averaging.

Comments:

Sierra Club and Clean Wisconsin object to inclusion of multi-facility averaging. They cite EPA's definition of RACT as "the lowest emission limit that a particular source is capable of meeting by application of control technology that is reasonably available…" Additionally they cite environmental justice concerns if RACT level of controls are not applied at WE Energies Valley Plant in downtown Milwaukee.

Although not specifically addressed in Alliant's or WE Energies' comments, it was apparent to DNR staff during initial rule development that multi-facility averaging is a critical compliance component for electric generating units in the rule.

Response:

Multi-facility averaging is a compliance option in the rule. In order to take advantage of the compliance option sources must obtain an additional 10% emission reduction beyond the source specific requirements. EPA's guidance document, *Improving Air Quality with Economic Incentive Programs,* provides the basis for application of an economic incentive program as the justification for the 10% additional emission reduction needed to implement an economic incentive program. Additionally, ozone is a regional pollutant. The production of ozone resulting from NOx emissions at power plants occurs far downwind from the source of NOx. The DNR is concerned about environmental justice, but in this case, people living in the vicinity of the smoke stacks are not exposed to higher concentrations of ozone than people living at greater distances.

4. Application of a Compliance Margin to Calculate RACT Emission Limits.

Comment:

Sierra Club and Clean Wisconsin argue that there is no need for a compliance margin in the rule, since they feel a compliance margin is already built into the proposed emission limits and the multi-facility averaging provides an additional compliance margin.

Response:

A compliance margin accommodates unforeseen circumstances such as control equipment that does not operate as efficiently as planned. Therefore, the Department affirms that inclusion of the compliance margin is appropriate in determining a RACT emission limit.

5. Definition of RACT Existing, NR428 meets RACT

Comment:

WMC argues that the existing NR428 meets the NOx RACT requirement.

Response:

The Department disagrees with WMC's conclusion. Existing NR428 was created to meet rate of progress requirements for the 1-hour ozone standard. In the 1-hour attainment demonstration, the Department determined that additional emission reductions, enough to accelerate attainment by at least one ozone season, were not economically feasible. To accelerate attainment, a very large amount of NOx emissions would need to be reduced over a short time. Given the limited number of opportunities for cheap, fast emission reductions in the Milwaukee area, Department staff found accelerating attainment infeasible when they developed the attainment demonstration for the 1-hour standard.

6. Combustion Tuning

Comments:

Clean Wisconsin supports the inclusion of combustion tuning in the rule, citing energy efficiency and cost effectiveness concerns.

Alliant, ANR Pipeline, Engine Manufacturers Association, WE Energies, Wisconsin Industrial Energy Group, Wisconsin Paper Council, and WMC cite numerous problems with the combustion tuning requirements. These commentors indicate, due to fuel prices, most sources already tune their boilers and therefore the requirement is unnecessary. These commentors also cite the modest emission reductions, stack testing and reporting requirements as problematic. ANR Pipeline indicated that combustion tuning should be eliminated for IC engines and turbines.

EPA indicated that alternative methods for combustion tuning that are approved by the Department must also be approved by EPA.

Response:

The Department proposes to drop combustion tuning from the NOx RACT rule. This provision wouldn't have accounted for very large emission reductions because it would have applied to smaller sources and some of the reductions will be achieved through voluntary combustion tuning.

The Department may consider combustion tuning in future air quality related initiatives such as PM2.5 or ozone attainment demonstrations, reasonable progress for haze or climate change proposals. In these new initiatives, DNR will work with industrial representatives to address their concerns and streamline testing and reporting requirements.

7. Emission Limits for EGUs

Comments:

Sierra Club and Clean Wisconsin indicate that the 2009 emission limits for power plants are too lenient. David Bender provided data for power plants in Kentucky and Texas showing that a continuous NOx emission limit at 0.04 lbs/mmBtu is not unreasonable.

Response:

DNR developed 2009 emission limits for power plants considering the time frame needed to permit and install operating equipment by 2009. Given that there are only two years before the May 1, 2009 compliance data, it is simply not possible to acquire funding, permit and install major pieces of control equipment such as SCR. Additionally, DNR developed emission limits capped at $2,500/ton. While it is true that NOx emission limits in the 0.04 lbs/mmBtu range can be achieved for various control equipment configurations, those control configurations are more costly than $2,500/ton.

8. Emission Unit Exemptions

Comments:

EPA indicates that any exemptions must be for sources where application of RACT is technologically or economically unreasonable. EPA goes on to indicate that the once in always in policy applies for sources that are required to install RACT controls. EPA also suggests language changes to clarify sources exempted due to federally enforceable limits.

James McCarthy, suggests creating a cut-off for combustion turbines, below which the sources would be exempt. WMC suggests increasing the exemption for low capacity units during the ozone season. Solar Turbine suggests exempting combustion turbines less than 25 MW

Response*:*

The Department modified the proposed exemptions to define emergency, auxiliary, and backup units which would normally qualify under the low operating unit exception. In addition, the Department has revised the capacity factor

used in calculating the utilization threshold to 20% for all source categories, increased the threshold to 75 tons per year in the revised rule, and created an exemption size threshold for simple cycle turbines at 25 MW.

9. In Attainment – No RACT Is Justified.

Comment:

WMC argues that RACT is not justified, since the area has already or will attain the 8-hour ozone standard in the near future.

Response:

Any regulatory requirement that should have been on the books at the time a re-designation request is submitted must still be adopted for the re-designation request to be complete. The NOx RACT submittal was due to EPA in September 2006. As such it is a past due requirement of the nonattainment areas and is necessary for EPA to consider approving our redesignation requests that will be submitted later this year. Notwithstanding the need to submit NOx RACT rules to support the redesignation requests, there are other reasons to develop and submit NOx RACT rules.

a. Sheboygan County remains in nonattainment status. A statistical analysis prepared by the DNR indicates that Sheboygan County has less than a 10% chance of attaining the 8-hour ozone standard after the 2007 ozone season.

b. EPA promulgated a new fine-particle standard in October 2006. Monitoring data from the most recent three years indicates that the Milwaukee/Waukesha area is violating that new fine-particle standard. NOx RACT will be a necessary part of any attainment plan for the fine-particles in Milwaukee/Waukesha nonattainment area.

c. EPA is in the process of promulgating a new ozone standard. They are under court order to finalize the standard by March 2008. The Clean Air Science Advisory Committee (CASAC), EPA's advisory group on air quality standards indicates, "There is no scientific justification for retaining the current primary 8-hr NAAQS of 0.08 parts per million (ppm), and … Therefore, *the CASAC unanimously recommends a range of 0.060 to 0.070 ppm for the primary ozone NAAQS*." If the standard is revised as CASAC recommends, it is very likely that the Milwaukee area will once again violate the ozone standard. RACT will once again be a requirement. Since there is a significant public health benefit to the NOx RACT rules, it is prudent to continue with RACT rules now instead of waiting for requirements from implementing a new standard.

d. NOx RACT rules will provide a significant public health benefit. Based on EPA's COBRA benefits model, the costs savings in public health benefit will be approximately $80,000,000/year, or about twice the cost of compliance.

10. Temporary Waivers for Outages

Comment:

Alliant suggested adding temporary waivers from emission limits to accommodate outages.

Response:

The Department believes that there is a need for a waiver for unforeseen circumstances that affect the reliability of the electric grid. That need for unforeseen circumstances is adequately covered in the rule. The Department does not agree that there is a need to provide such a waiver for planned outages.

11. Competitive Disadvantage

Comment:

WMC indicates that application of RACT in the Wisconsin's non-attainment area will put Wisconsin sources at a competitive disadvantage.

Response:

Application of RACT is required by federal law. Further, for example, the Chicago 8-hour ozone nonattainment area is immediately adjacent to the Milwaukee nonattainment. Illinois is in the process of developing NOx RACT rules as well. Illinois current proposal includes a statewide NOx RACT with emission limits commensurate with those in Wisconsin's proposed rule. Additionally, Illinois has negotiated multi-pollutant agreements with their major power producers, representing about 90% of the generating capacity in the state. Those emission limits are more stringent

than the ones proposed in our rule. Therefore, application of NOx RACT in Wisconsin does not appear to put our sources at a competitive disadvantage, at least, with a state that shares a border and has similar air quality circumstances to our own.

12. Compliance Schedule, Move Phase 2 Limits to 2015

Comment:

WIEG commented that the second phase of the RACT compliance should be moved to 2015 to make it consistent with the second phase of the Clean Air Interstate Rule.

Response:

The compliance date for RACT is May 1, 2009, but the Department is allowing a later final compliance date, May 1, 2013, for electric utilities to come into compliance. Because the Department believes that final compliance for large installations at power plants cannot occur within two years, the Department proposed the 2013 date in the public hearing draft. EPA must approve our SIP. From discussions with that agency, we do not believe that a later compliance date would be allowed under federal regulations and guidance. In addition, the Department did not receive any data to support the extension of the final compliance date to beyond 2013. Therefore, extending the compliance date beyond 2013 is not justified.

13. RACT Limit for Combustion Turbines

Comments:

Solar Turbine suggests: Breaking the combustion turbine category into subcategories; smaller combustion turbines cannot meet the emission limits without expensive add-on controls; simple-cycle gas turbines could not meet a 9 ppm limit for retrofitted equipment and recommended specific emission limits for these turbines; different limits for liquid-fired turbines; other parameters to determine compliance.

Waste Management suggested that contaminants in land-fill gas can render SCR and SNCR ineffective. Additionally, the requirements for combustion turbines make the beneficial use of land-fill gas uneconomical. Waste Management argues that there is a net reduction of using land-fill gas in combustion turbines versus flaring the gas.

Response:

In response to comments, the Department created an exemption size threshold for simple cycle turbines at 25 MW. The Department also adjusted emission limits for all combustion turbine categories to reflect available low NOx combustion techniques without the use of post-combustion control.

14. Definition of Wall-Fired Boiler with Maximum Heat Rate between 500 to1000 mmBtu/hr.

Comments:

WE Energies suggested that DNR change the language in the rule that describes wall-fired boilers in the 500 to1000 mmBtu/hr range to language that reflects industry standards for such boilers. The issue is large heat release for some wall-fired boilers compared to the physical size of the boiler.

Response:

DNR agrees with the comment and has made the suggested change.

15. Green Tier

Comment:

EPA indicates that inclusion of the Green Tier program as a compliance strategy will necessitate submitting the Green Tier program as part of Wisconsin's federal enforceable state implementation plan (SIP).

Response:

While the Department strongly supports the goals of the Green Tier program, we believe that the Green Tier program being a federally enforceable part of the SIP would delay promulgation of this rule and might be counter to the Green Tier program goals. Therefore, we've dropped the proposed Green Tier language in this rule that

was only a general reference to the program anyway. The Department will continue to search for ways to take advantage of the Green Tier program to achieve superior environmental goals.

16. Alternative Monitoring Strategies

Comment:
EPA indicates that any alternative monitoring strategy approved by the Department must also be approved by EPA.

Response:
DNR has made the change to insure EPA approval.

17. Monitoring, Recordkeeping and Reporting

Comment:
EPA indicates that the Department's rule should clarify how records are to be kept. ANR Pipeline objected to CEMs for turbines and periodic testing for IC engines. The Engine Manufacturers Association indicates that IC engines almost always operate at full load so, only testing at 100% load is necessary. Waste Management indicates that periodic testing for IC engines burning land-fill gas is not cost effective.

Response:
The Department revised the rule to streamline monitoring requirements without compromising the compliance demonstration. The public hearing draft rule allowed an alternative EPA monitoring method with written approval of the department. The revised rule will allow this alternative without approval for specific source categories. Other miscellaneous modifications have been made based on comments to address consistency in test method standards and for certain source categories and to clarify portions of the rule.

18. Alternative Compliance Methods

Comment:
EPA indicates that averaging times longer than 30 days rolling averages need to meet requirements of a 1993 guidance memo, "Fuel Switching to Meet the Reasonably Available Control Technology Requirements for Nitrogen Oxides."

Response:
After subsequent discussions, EPA concluded that the compliance averaging times in the public hearing draft of the rule were approvable.

19. Electric Reliability Waiver

Comment:
EPA states that the rule should be clarified so that it is clear the intent is not to delay the May 1, 2009 compliance date. EPA indicates that this type of enforcement discretion has been used in the past, for instance, to allow non-spec gasoline after a refinery explosion.

Response:
DNR revised the rule to add EPA's approval as well as the Department's approval for the waiver.

20. No Environmental Benefit for Controlling Small IC Engines and Turbines

Comment:
ANR Pipeline indicates that there is no environmental benefit for controlling small units and that the minimum size threshold for internal combustion engines and for combustion turbines should be increased.

Response:
The Department raised exemption threshold for affected engines from 250 to 500 hp. Additionally, the Department revised emission limits for natural gas fired engines to 3.0 gr/bhp-hr.

21. Control Technology for Gas Transmission Sources

Comments:

ANR Pipeline indicate that natural gas transmission stations are designed with excess capacity that results in low utilization, so emission reductions are costly compared to the actual amount of reduction. ANR further comments that the proposed rule is not consistent with recent EPA action and that DNR inappropriately identified control technology for rich-burn IC engines.

Response:

The Department included natural gas transmission stations among the source types eligible for the reliability waiver. The Department does not agree that including this category is inappropriate.

22. Waiver for Natural Gas Transmission Stations from RACT Controls

Comment:

ANR Pipeline indicates that natural gas transmission stations should get a waiver from NOx RACT controls.

Response:

No such waiver is allowed under the federal Clean Air Act.

23. Emission Limits for Lean-Burn IC Engines

Comment:

The Engine Manufacturers Association commented that the emission factor and cost analysis for lean-burn IC engines was inaccurate and needs to be revised.

Response:

In response to this comment, the Department raised the exemption threshold for affected engines to 500 hp. Additionally, the Department revised emission limits for natural gas fired engines to 3.0 gr/bhp-hr.

Wisconsin Department of Administration
Division of Executive Budget and Finance
DOA-2048 (R10/2000)

Fiscal Estimate — 2007 Session

☒ Original ☐ Updated	LRB Number	Amendment Number if Applicable
☐ Corrected ☐ Supplemental	Bill Number	Administrative Rule Number AM-17-05

Subject

RACT rules in s. NR 428.21 to 428.24 for major sources of NOx emissions in the ozone non-attainment counties of Kenosha, Racine, Milwaukee, Waukesha, Washington, Ozaukee, and Sheboygan.

Fiscal Effect

State: ☐ No State Fiscal Effect

Check columns below only if bill makes a direct appropriation or affects a sum sufficient appropriation.

☐ Increase Existing Appropriation ☐ Increase Existing Revenues
☐ Decrease Existing Appropriation ☒ Decrease Existing Revenues
☐ Create New Appropriation

☒ Increase Costs — May be possible to absorb within agency's budget. ☒ Yes ☐ No

☐ Decrease Costs

Local: ☒ No Local Government Costs

1. ☐ Increase Costs ☐ Permissive ☐ Mandatory	3. ☐ Increase Revenues ☐ Permissive ☐ Mandatory	5. Types of Local Governmental Units ☐ Towns ☐ Villages ☐ Cities ☐ Counties ☐ Others ☐ School Districts ☐ WTCS Districts
2. ☐ Decrease Costs	4. ☐ Decrease Revenues	

Fund Sources Affected	Affected Chapter 20 Appropriations
☐ GPR ☐ FED ☒ PRO ☐ PRS ☐ SEG ☐ SEG-S	20.370 2(bg)

Assumptions Used in Arriving at Fiscal Estimate

The Department is proposing this rule package to meet Clean Air Act requirements for implementing a reasonably available control program for NO_x emissions from major sources capable of emitting 100 tons per year or more of nitrogen oxides in the moderate ozone non-attainment counties. The affected emission units include electric utility generating units and industrial combustion emission units. The majority of emission units are subject to emission limitations and good combustion requirements with a set of smaller emission units only subject to good combustion requirements.

1. Impact on the Department:

The annual emissions fees paid to the department are affected by the reduction in NOx emissions. The estimated reduction related to RACT controls achieved by 2013 is approximately 19,000 tons of NOx annually below 2004 emission levels. The related reduction in emission fees or reduced revenue to the department is approximately $390,000 to $438,000 per year beginning in 2013.

2. Impact to government affected facilities:

The UW-Milwaukee facility has three boilers used for heating and cooling purposes. The units already have combustion modifications in place sufficient to meet rule emission limitation requirements. The facility may have to implement recordkeeping and additional monitoring to meet good combustion requirements at a minimum net cost increase.

3. Impact on non-government affected facilities

These cost estimates are based on general cost assumptions and factors applicable to each of the source categories.

The proposed rule requires the most significant reductions from thirteen coal-fired electric utility boilers. The primary cost of reduction for these units is due to the anticipated installation and operation of major post

Long-Range Fiscal Implications

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Wisconsin Department of Administration
Division of Executive Budget and Finance
DOA-2048 (R10/2000)

Fiscal Estimate — 2007 Session

☒ Original	☐ Updated	LRB Number	Amendment Number if Applicable
☐ Corrected	☐ Supplemental	Bill Number	Administrative Rule Number AM-17-05

Subject

NOx RACT rules in s. NR 428.21 to 428.24 for major sources in the ozone non-attainment counties of Kenosha, Racine, Milwaukee, Waukesha, Washington, Ozaukee, and Sheboygan.

(Assumptions Used in Arriving at Fiscal Estimate , page 2)

combustion pollution control equipment. The costs for electric utilities are expected to be in the range of $10-$15 million per year. The estimated cost-effectiveness for the affected utility units ranges from $1,000 to $2,200 per ton of removed NO_x. The total cost represents approximately 0.2 cents per kWh. Approximately one half of the total annual cost is related to a portion of the total expected controls already in place to meet other requirements. It should be noted that these NO_x reductions may overlap to some degree with other NO_x reductions required in the CAIR and BART proposed rule packages, but the estimated fiscal cost is not additive between the proposed rules affecting the electric utility sector.

Additionally, the proposed emission limits may affect approximately 47 industrial emission units. The estimated total cost for these sources is subject to some uncertainty for several reasons: a) sources may not be subject to the emission limits due to being below the potential to emit; b) some sources appear to not have significant operation during the ozone season and therefore are exempt from the emission limits, and c) some of the affected units are expected to already be operating below the RACT emission limits. The cost of control for the industrial sources is expected to be in the range $1,200,000 to $2,000,000 per year or up to approximately $2,500 per ton of removed NO_x.

4. Health cost savings. There will be a significant public health benefit associated with implementing the rule. Health related costs for the citizens of Wisconsin will be reduced by at least 2 to 5 times the cost of compliance based on estimates from an EPA's COBRA model, a screening tool used to: approximate the impact of emission changes on ambient air pollution; translate this into health effect impacts; monetize these impacts; and present the results in maps and tables.

Wisconsin Department of Administration
Division of Executive Budget and Finance
DOA-2047 (R10/2000)

Fiscal Estimate Worksheet — 2007 Session

Detailed Estimate of Annual Fiscal Effect

☒ Original	☐ Updated	LRB Number	Amendment Number if Applicable
☐ Corrected	☐ Supplemental	Bill Number	Administrative Rule Number AM-17-05

Subject

NOx RACT rules in s. NR 428.21 to 428.24 for major sources in the ozone non-attainment counties of Kenosha, Racine, Milwaukee, Waukesha, Washington, Ozaukee, and Sheboygan.

One-time Costs or Revenue Impacts for State and/or Local Government (do not include in annualized fiscal effect):

Annualized Costs:	Annualized Fiscal Impact on State Funds from:	
A. State Costs by Category	Increased Costs	Decreased Costs
State Operations — Salaries and Fringes	$	$ -
(FTE Position Changes)	(FTE)	(- FTE)
State Operations — Other Costs		-
Local Assistance		-
Aids to Individuals or Organizations		-
Total State Costs by Category	$	$ -
B. State Costs by Source of Funds	Increased Costs	Decreased Costs
GPR	$	$ -
FED		-
PRO/PRS		-
SEG/SEG-S		-
State Revenues — Complete this only when proposal will increase or decrease state revenues (e.g., tax increase, decrease in license fee, etc.)	Increased Revenue	Decreased Revenue
	$	$ -
GPR Earned		-
FED		-
PRO/PRS		- 390,000
SEG/SEG-S		
Total State Revenues	$	$ -390,000

Net Annualized Fiscal Impact

	State	Local
Net Change in Costs	$ 0	$ 0
Net Change in Revenues	$ -390,000	$ 0

Prepared By:	Telephone No.	Agency
Joe Polasek	266-2794	Department of Natural Resources
Authorized Signature	Telephone No.	Date (mm/dd/ccyy)
	266-2794	

Form 1100-1
(R 2/01)

NATURAL RESOURCES BOARD AGENDA ITEM

Item No. _____

SUBJECT: Order AM-17-05, Adoption of sections NR 428.20 to 428.27 concerning NOx RACT rules and associated reference incorporations into NR 484.04.

FOR: April 2007 Board Meeting

TO BE PRESENTED BY: Larry Bruss / Regional Pollutant and Mobile Source Section Chief

SUMMARY: The Clean Air Act requires the implementation of reasonably available control technology (RACT) on major sources of NO_x emissions in the moderate non-attainment counties by 2009. To develop the proposed rules, the Department used the flexibility that EPA allows in creating RACT rules. However, these proposed rules do not exceed federal Clean Air Act requirements.

The proposed RACT rules require emission limits for emission units at facilities with the potential to emit of 100 tons of NO_x per year in the counties of Kenosha, Racine, Milwaukee, Waukesha, Washington, Ozaukee, and Sheboygan. The source categories include electric utility boilers, industrial sized boilers, combustion turbines, glass and steel furnaces, reciprocating engines, and other miscellaneous large combustion processes. The Department estimates that 49 emission units in these counties may need to install control equipment to meet the emission limits in the proposed rule. The potentially affected sources emit approximately 29,000 tons per year of NOx (2005 emission levels). The RACT emission limits will reduce emissions by approximately 15,000 tons of NOx per year by May 1, 2013. The maximum control cost (from uncontrolled levels) for all affected sources will be approximately $2,500 per ton of NO_x removed.

The Board authorized a public hearing on the proposed rule at its January, 2007 meeting. A public hearing was held in Milwaukee on March 15th, 2007 and public comments were accepted through March 19, 2007. Substantial revisions to the rule are proposed as a result of public comments. These changes are summarized in Attachment C to the background memo.

RECOMMENDATION: Adopt NOx RACT Rule.

LIST OF ATTACHED MATERIALS:

No ☐	Fiscal Estimate Required	Yes ☒ Attached
No ☒	Environmental Assessment or Impact Statement Required	Yes ☐ Attached
No ☐	Background Memo	Yes ☒ Attached

APPROVED:

_____ _____
Bureau Director, Kevin Kessler Date

_____ _____
Administrator, Al Shea Date

_____ _____
Secretary, Scott Hassett Date

cc: Amy Lemberger - AD/5
Carol Turner - LS/5
K. Kessler - AM/7
R. Eckdale - AM/7 (10)
Tom Karman - AM/7

STAFF REVIEW - DNR BOARD AGENDA ITEM

REMINDER

Have the following questions been answered under the summary section of this form?

- -Why is the rule needed?
- -What are the significant changes?
- -What are the key issues/controversies?
- -What was the last action of the Board?

LIST OF ATTACHED REFERENCE MATERIAL REQUIRED FOR RULE PROPOSALS:

Hearing authorization:	Final adoption:
Background memo (if needed)*	Background Memo (if needed)*
Fiscal Estimate	Response Summary
Environmental Assessment (if needed)	Fiscal Estimate
Rule	Environmental Assessment (if needed)
	Rule

* If all the questions listed in the REMINDER section above can be adequately summarized on the Green Sheet (and a second sheet if needed), the Background Memo may be omitted.

Unit	Reviewer	Date	Comments
Environmental Analysis and Review			
Management and Budget			
Legal Services -Program Attorney -Carol Turner			

Other (if applicable)			

ORDER OF THE STATE OF WISCONSIN
NATURAL RESOURCES BOARD
AMENDING AND CREATING RULES

The Wisconsin Natural Resources Board proposes an order to **amend** 428.04(2)(h)1. and 2., 428.05(3)(e)1. to 4. and 484.04(13), (21m), (26m)(d), and (27) and **create** NR 428.02(7m), 428 subch. IV and 484.04 (15m),(16m) and (26m)(bm) relating to implementation of Reasonably Available Control Technology (RACT) NO_x emission limitations applicable to major sources in the 8-Hour ozone non-attainment area in southeastern Wisconsin.

AM-17-05

Summary Prepared by the Department of Natural Resources

1. **Statute interpreted:** s. 285.11(6), Stats. The State Implementation Plan developed under s. 285.11(6), Stats., is revised.

2. **Statutory authority:** s. 227.11(2)(a) and 285.11(1) and (6), Stats.

3. **Explanation of agency authority:** Section 227.11(2)(a), Stats., gives state agencies general rule-making authority. Section 285.11(1) Stats., gives the Department the authority to promulgate rules consistent with ch. 285, Stats. Section 285.11(6), Stats., authorizes the Department to develop and revise a state implementation plan for the prevention, abatement and control of air pollution.

4. **Related statute or rule:** The current provisions of ch. NR 428 established nitrogen oxide emission limits for new and existing facilities which are located in the 1-hour ozone nonattainment counties. The primary intent in creating these past provisions of ch. NR 428 was to fulfill Clean Air Act (CAA) requirements for demonstrating rate-of-progress towards attaining the 1-hour ozone standard. The proposed rule will create a new subchapter in ch. NR 428 for purposes of establishing Reasonably Available Control Technology (RACT) emission limitations for major sources of nitrogen oxide emissions in counties designated as nonattainment under the 8-hour ozone standard. Modifications are also proposed to existing portions of ch. NR 428 in relation to the creation of the new subchapter and in s. NR 484.04 to reflect incorporation by reference of standards.

5. **Plain language analysis:** The Clean Air Act requires states to adopt and implement a control program of reasonably available control technology (RACT) for major NO_x stationary sources in the moderate ozone nonattainment area. To meet this requirement, the proposed rule establishes emission limits and compliance requirements for emission units at facilities with a total potential to emit of 100 tons/year of NO_x. The proposed RACT rules conform to the federal Clean Air Act.

The Department determined that $2,500/ton of NOx removed, from an uncontrolled baseline, is an appropriate upper limit for application of RACT at an affected facility. The Department's proposed emission limits for electric utility generating units and larger industrial emission units are based on that upper limit. The source categories affected by the rule include industrial boilers, combustion turbines, glass and steel furnaces, reciprocating engines, and other miscellaneous large combustion processes.

The emission limits are designated by source category and fuel type as necessary, but are not applicable unless the unit is operated over an utilization threshold during the ozone season as specified in the rule for each source category. The operating threshold for exemption is based on 20% of the source category's unit size threshold for defining the smallest unit subject to the emission limit. The proposed rule also exempts emission units from further control if the unit is already meeting an existing NOx emission limit under ch. NR. 428 and emits less than 75 tons per year of NO_x. And the rule lists specific units such as emergency generators, fire-fighting water pumps, peaking units, etc.. which also are exempt from the emissions limits. However, once an emissions unit no longer qualifies for one of the exemptions, it is subject to the emission limitations on an ongoing basis.

The rule provides compliance flexibility by providing phased implementation for electric generation units subject to CAIR, emissions averaging programs, alternative RACT determinations, demonstration of CAIR actions satisfying RACT emission limits, and a reliability waiver option.

Sources demonstrate compliance with the emission rate limits by 1) Installing and operating continuous emissions monitoring systems (CEMs) consistent with 40 CFR part 60 requirements for units with considerable variability in operation, 2) Performance stack testing every 2 years for units with less variability in operation or emissions, or 3) Continuous parametric monitoring of combustion parameters with stack testing every 5 years for all gaseous and oil fired units. The rule allows an owner to request an alternative to any of the emissions monitoring requirements.

6. **Summary of, and comparison with, existing or proposed federal regulation:** In 2004, the federal NO_x SIP Call became effective in 21 eastern states requiring control of NO_x emissions. However, the NOx SIP call did not apply to Wisconsin. The sources affected by the SIP call include electric utility generating units greater than 25 megawatts and very large industrial emission units. The USEPA estimated the cost of meeting the NO_x SIP call requirements to be approximately $2,000/ton of controlled NO_x emissions and described this as “highly cost-effective.” The Wisconsin NO_x RACT rule is based on considering controls with a cost ceiling of $2,500 per ton of NO_x.

The EPA is requiring implementation of best available retrofit technology (BART) control by 2013 to reduce NOx emissions from certain large emission sources which have visibility impacts in scenic Class I areas. The BART requirement is a case-by-case determination and, therefore, cannot be accurately represented for this discussion. However, EPA assumes default BART controls resulting in approximately 50% to 90% reduction in NO_x emissions. The proposed emission limits in the Wisconsin rule are similar and do not exceed an anticipated 90% reduction for similar sources.

The proposed RACT rule proposes emission limits for the type of industrial sources that would be affected by federal NOx SIP Call or BART requirements. The proposed emission limits for industrial sources reflect a control cost range of approximately $500 to $2,500 per ton of NO_x removed. The proposed controls for electric utility generating sources reflect a cost range of approximately $1,000 to $2,200 per ton of NO_x. The proposed emission limits in the Wisconsin rule are similar to default BART levels and do not exceed an anticipated 90% reduction for similar sources. It should be noted that both the NOx SIP Call and BART regulations primarily affect larger sources and that the proposed RACT rule establishes emission limits for additional sources based on the CAA definition of a major sources and the level of cost-effectiveness considered for this rule.

7. **Comparison with rules in adjacent states:** States near Wisconsin with 8-hour ozone nonattainment areas are Illinois, Indiana, Michigan and Ohio. Illinois, Indiana and Ohio also have moderate non-attainment areas. All of the Michigan nonattainment areas are of a lower non-attainment designation of either "basic" or "marginal".

Illinois: The state of Illinois has proposed a statewide RACT rule for industrial boilers and other sources with a potential to emit of 100 tons per year or greater. The Illinois rule affects smaller sources and implements equivalent or more stringent requirements than those in the Wisconsin rule. The Illinois proposed RACT emission limits are based on a cost-effectiveness ranging up to $2,500 per ton of NO_x removed. The rule proposes combustion tuning for boilers between 50 and 100 mmbtu/hr and emission limits for units approximately equivalent to 50 mmbtu/hr across the source categories. Illinois EPA negotiated very stringent SO_2 and NOx limitations with the utilities in Illinois that generate about 90% of the electric power in the state. The resulting emission limits for the Chicago area are more stringent than what the Department has proposed for NOx RACT in the Milwaukee area.

Indiana: Indiana is not proceeding with NOx RACT rule development at this time.

Michigan: The state of Michigan has made no determination regarding the need for developing RACT rules. A Michigan RACT rule is required only if attainment in the basic areas cannot be demonstrated by the state's SIP submittal deadline of June 2007.

Ohio: Ohio is developing NOx RACT rules for industrial sources in the Cleveland nonattainment area. The rule affects smaller sources and implements equivalent or more stringent requirements than the Wisconsin rule for industrial sources. The proposed Ohio rule considers controls up to $5,000 per ton of controlled NOx. The proposal requires combustion tuning for boilers between 20 and 50 mmBtu/hr. Emission units approximately 50 mmbtu/hr and larger across source categories must meet emission limits.

8. **Summary of factual data and analytical methodologies:**

Department staff identified potentially affected units and source categories based on information contained in the air emissions inventory and source permits. A review of available emission control technologies and options was conducted based on available EPA resources, industry information, and other technical resources. General control assumptions and cost factors for each source category were used in evaluating appropriate emission limits and applicability. The proposed emission limitations were also compared to both existing and proposed RACT emission limits or NO_x emission control programs in other states. The department considered technical information obtained through the public comment period as applicable to each source category.

9. **Analysis and supporting documents used to determine effect on small business or in preparation of economic impact report:**

The proposed rule is expected to affect only large industrial sources and therefore it is not anticipated to have an impact on small businesses.

10. **Effect on small business:**

The proposed rule is expected to affect only large industrial sources and therefore it is not anticipated to have an impact on small businesses.

11. **Agency contact person:**

Thomas Karman
Thomas.karman@dnr.state.wi.us
(608) 264-8856

The consent of the Attorney General and the Revisor of Statutes will be requested for the incorporation by reference of new test methods in ch. NR 484.

SECTION 1. NR 428.02(7m) is created to read:

NR 428.02(7m) "Process heater" means an enclosed device using controlled flame, that is not a boiler, and that has a primary purpose to transfer heat indirectly to a process material or to a heat transfer material for use in a process unit, instead of generating steam. Process heaters may not include combustion equipment where the material being heated is in direct contact with the products of combustion, such as furnaces or kilns, any unfired waste heat recovery heater or units used for comfort heat or space heat, food preparation for onsite consumption, or autoclaves.

SECTION 2. NR 428.04(2)(h)1. and 2. are amended to read:

NR 428.04(2)(h)1. 6.9 grams per brake horsepower-hour for a compression ignition unit with a maximum design power output of 1000 hp or greater.

2. 4.0 grams per brake horsepower-hour for a spark ignition unit with a maximum design power output of 1000 hp or greater.

SECTION 3. NR 428.05(3)(e)1. to 4. are amended to read:

NR 428.05(3)(e)1. 9.5 grams per brake horsepower-hour for rich-burn units.

2. 10.0 grams per brake horsepower-hour for lean-burn units.

3. 8.5 grams per brake horsepower-hour for distillate fuel oil-fired units.

4. 6.0 grams per brake horsepower-hour for dual-fuel units.

SECTION 4. NR 428 subch. IV to follow NR 428.11 is created to read:

SUBCHAPTER IV

NO_X REASONABLY AVAILABLE CONTROL TECHNOLOGY REQUIREMENTS

NR 428.20 Applicability and purpose. (1) APPLICABILITY. The requirements of this subchapter apply to the owner or operator of a NO_X emissions unit which is in a source category identified in s. NR 428.22 and which is located at a facility with a combined total potential to emit for all

NO_X emissions units of 100 tons per year or more of NO_X and which is in the counties of Kenosha, Milwaukee, Ozaukee, Racine, Sheboygan, Washington or Waukesha.

(2) PURPOSE. The purpose of this subchapter is to establish reasonably available control technology requirements for NO_X emissions units in the ozone nonattainment area consisting of the counties of Kenosha, Milwaukee, Ozaukee, Racine, Sheboygan, Washington and Waukesha to comply with sections 172(c) and 182(f) of the Act (42 USC 7502(c) and 7511a(f)).

NR 428.21 Emissions unit exceptions. The emissions units described in subs. (1), (2) and (3) are exempt from the emission limitation requirements of s. NR 428.22, but shall comply with applicable record keeping requirements under s. NR 428.24. Once an emissions unit no longer qualifies for an exemption, the owner or operator of the emission unit shall comply with the requirements of s. NR 428.22 by December 31 of the following calendar year, unless an alternate date is approved in writing by the department and the administrator.

(1) GENERAL EXEMPTIONS. The following emissions units and processes are exempt from the emission limitations in s. NR 428.22:

(a) Any emissions unit operated only to restart electric generation in the event of a complete loss of facility power.

(b) Any emissions unit which is operated no more than 500 hours per year and no more than 200 hours during the ozone season and whose only purpose is to provide electricity to a facility if normal electricity service is interrupted or to replace normal critical operations at a facility.

(c) Any emissions unit whose only function is to pump water in the case of a fire emergency.

(d) Any emissions unit whose utilization is less than 10% of its capacity factor on an annual average basis over a 3-year rolling period and less than 20% of its capacity factor in any year of the 3-year rolling period and which is owned or operated by an electric generation utility or gas transmission utility.

(e) A research or development unit.

(f) An engine testing operation or process line.

(d) Any gaseous fuel fired unit used to control VOC emissions from a commercial or industrial process.

(2) LOW OPERATING UNIT. An emissions unit described in s. NR 428.20 is exempt from the emission limitations of s. NR 428.22 if, during each ozone season, the emissions unit's utilization based on actual measured heat input or output is less than the utilization threshold for the source category according to the following equation:

UU_i < (Category capacity) x (3,672 hours / Ozone Season) x Capacity Factor Equation 1

where:

UUi is the unit's actual fuel consumption or output in measurement units consistent with the calculated utilization threshold for the source category in s. NR 428.22

Category capacity is the lower value in the range of unit capacity or design output used to describe the unit's source category i in s. NR 428.22

Capacity factor is 0.20 for all source categories in s. NR 428.22

(3) OTHER REGULATED UNIT. An emissions unit which is subject to and meeting an emission limitation in s. NR 428.04 or 428.05(3) and which is subject to a federally enforceable condition in an air permit issued prior to January 1, 2006 which limits emissions to no more than 75 tons of NO_X per year is exempt from the emission limitations in s. NR 428.22.

NR 428.22 Emission limitation requirements. (1) EMISSION LIMITS. Except as provided in sub. (2), on or after May 1, 2009, no person may cause, allow or permit NO_X to be emitted in excess of the following emission limitations on a 30-day rolling average basis:

(a) *Boilers.* 1. For a solid fuel-fired boiler with a maximum heat input capacity equal to or greater than 1,000 mmBtu per hour, one of the following, as applicable:

a. If tangential, wall, cyclone or fluidized bed-fired, 0.10 pound per mmBtu of heat input.

b. If arch-fired, 0.18 pound per mmBtu of heat input.

2. For a solid fuel-fired boiler with a maximum heat input capacity equal to or greater than 500 mmBtu per hour and less than 1,000 mmBtu per hour, one of the following, as applicable:

a. If tangential-fired, 0.15 pound per mmBtu of heat input.

b. If wall-fired with a heat release rate equal to or greater than 17,000 Btu per cubic feet per hour, 0.17 pound per mmBtu of heat input.

c. If wall-fired with a heat release rate less than 17,000 Btu per cubic feet per hour, 0.15 pound per mmBtu of heat input.

d. If cyclone-fired, 0.15 pound per mmBtu of heat input.

e. If arch-fired, 0.18 pound per mmBtu of heat input.

g. If fluidized bed-fired, 0.10 pound per mmBtu of heat input.

3. For a solid fuel-fired boiler with a maximum heat input capacity equal to or greater than 250 mmBtu per hour and less than 500 mmBtu per hour, one of the following, as applicable:

a. If tangential-fired, 0.15 pound per mmBtu of heat input.

b. If wall-fired with a heat release rate equal to or greater than 17,000 Btu per cubic feet per hour, 0.17 pound per mmBtu of heat input.

c. If wall-fired with a heat release rate less than 17,000 Btu per cubic feet per hour, 0.15 pound per mmBtu of heat input.

d. If cyclone-fired, 0.15 pound per mmBtu of heat input.

f. If arch-fired, 0.18 pound per mmBtu of heat input.

g. If fluidized bed-fired, 0.10 pound per mmBtu of heat input.

h. If stoker-fired, 0.20 pound per mmBtu of heat input.

4. For a solid fuel-fired boiler with a maximum heat input capacity equal to or greater than 50 mmBtu per hour and less than 250 mmBtu per hour, one of the following, as applicable:

a. If tangential-fired, 0.15 pound per mmBtu of heat input.

b. If wall-fired with a heat release rate equal to or greater than 17,000 Btu per cubic feet per hour, 0.17 pound per mmBtu of heat input.

c. If wall-fired with a heat release rate less than 17,000 Btu per cubic feet per hour, 0.15 pound per mmBtu of heat input.

d. If cyclone-fired, 0.15 pound per mmBtu of heat input.

e. If fluidized bed-fired, 0.10 pound per mmBtu of heat input.

f. If stoker-fired, 0.25 pound per mmBtu of heat input.

5. For a gaseous fuel-fired boiler with a maximum heat input capacity equal to or greater than 100 mmBtu per hour, 0.08 pound per mmBtu of heat input.

6. For a distillate fuel oil-fired boiler with a maximum heat input capacity equal to or greater than 100 mmBtu per hour, 0.10 pound per mmBtu of heat input.

7. For a residual fuel oil-fired boiler with a maximum heat input capacity equal to or greater than 65 mmBtu per hour, 0.15 pound per mmBtu of heat input.

(b) *Lime kilns.* For a lime kiln with a maximum heat input capacity equal to or greater than 50 mmBtu per hour, one of the following as applicable:

1. For a gaseous fuel-fired unit, 0.10 pound per mmBtu of heat input.

2. For a distillate oil-fired unit, 0.12 pound per mmBtu of heat input.

3. For a residual oil-fired unit, 0.15 pound per mmBtu of heat input.

4. For a coal-fired unit, 0.60 pound per mmBtu of heat input.

5. For a coke-fired unit, 0.70 pound per mmBtu of heat input.

(c) *Reheat, annealing or galvanizing furnaces.* For a reheat, annealing or galvanizing furnace with a maximum heat input capacity equal to or greater than 75 mmBtu per hour, 0.08 pounds per million Btu of heat input.

(d) *Glass furnaces.* For a glass manufacturing furnace with a maximum heat input capacity equal to or greater than 50 mmBtu per hour, 2.0 pounds per ton of produced glass.

(e) *Asphalt plants.* For an asphalt plant with a maximum heat input capacity equal to or greater than 65 mmBtu per hour, one of the following as applicable:

1. For a gaseous fuel-fired unit, 0.15 pound per million Btu of heat input.

2. For a distillate fuel oil-fired unit, 0.20 pound per million Btu of heat input.

3. For a residual fuel oil-fired or waste oil-fired unit, 0.27 pound per million Btu of heat input.

(f) *Process heating.* For a process heater, dryer, oven or other process heating device, one of the following as applicable:

1. For a gaseous fuel-fired unit with a maximum heat input capacity equal to or greater than 100 mmBtu per hour, 0.10 pound per mmBtu of heat input.

2. For a distillate oil-fired unit with a maximum heat input capacity equal to or greater than 100 mmBtu per hour, 0.12 pound per mmBtu of heat input.

3. For a residual oil-fired unit with a maximum heat input capacity equal to or greater than 65 mmBtu per hour, 0.18 pound per mmBtu of heat input.

(g) *Simple cycle combustion turbines*. For a simple cycle combustion turbine, one of the following exhaust outlet concentrations, corrected to 15% O_2 and at ambient temperatures greater than 0^oF, as applicable:

1. For a unit with a maximum design power output equal to or greater than 50 megawatts, one of the following, as applicable:

a. If natural gas-fired, 25 parts per million dry volume.

b. If distillate oil fuel-fired, 65 parts per million dry volume.

c. If biologically derived gaseous fuel-fired, 35 parts per million dry volume.

2. For a unit with a maximum design power output equal to or greater than 25 megawatts and less than 50 megawatts, one of the following as applicable:

a. If natural gas-fired, 42 parts per million dry volume.

b. If distillate oil fuel-fired, 96 parts per million dry volume.

c. If biologically derived gaseous fuel-fired, 35 parts per million dry volume.

(h) *Combined cycle combustion turbines.* For a combined cycle combustion turbine, one of the following exhaust outlet concentrations, corrected to 15% O_2 and at ambient temperatures greater than 0^oF, as applicable:

1. For a natural gas-fired unit with a maximum design power output equal to or greater than 25 megawatts, 9 parts per million dry volume.

2. For a natural gas-fired unit with a maximum design power output equal to or greater than 10 megawatts and less than 25 megawatts, 42 parts per million dry volume.

3. For a distillate oil fuel-fired unit with a maximum design power output equal to or greater than 10 megawatts, 42 parts per million dry volume.

4. For a biologically derived gaseous fuel-fired unit with a maximum design power output equal to or greater than 10 megawatts, 35 parts per million dry volume.

(i) *Reciprocating engines.* For a reciprocating engine with a maximum design power output equal to or greater than 500 horsepower, one of the following as applicable:

1. For a rich-burn spark ignition unit, 3.0 grams per brake horsepower-hour.

2. For a lean-burn spark ignition unit, 3.0 grams per brake horsepower-hour.

3. For a diesel fuel-fired compression unit, 3.0 grams per brake horsepower-hour.

4. For a dual fuel-fired compression unit, 3.0 grams per brake horsepower-hour.

(2) ELECTRIC UTILITY BOILER COMPLIANCE SCHEDULE. The owner or operator of an electric utility boiler subject to the provisions of 40 CFR part 97 shall demonstrate compliance with the following interim NO_x emission limitations, as applicable, on a 30-day rolling average by May 1, 2009 and with the emission limitations in sub. (1)(a) on and after May 1, 2013:

(a) For a solid fuel-fired boiler with a maximum heat input capacity equal to or greater than 1,000 mmBtu per hour, one of the following, as applicable:

1 If tangential, wall, cyclone or fluidized bed-fired, 0.15 pound per mmBtu of heat input.

2. If arch-fired, 0.18 pound per mmBtu of heat input.

(b) For a solid fuel-fired boiler with a maximum heat input capacity equal to or greater than 500 mmBtu per hour and less than 1,000 mmBtu per hour, one of the following, as applicable:

1. If tangential-fired, 0.15 pound per mmBtu of heat input.

2. If wall-fired, 0.20 pound per mmBtu of heat input.

3. If cyclone-fired, 0.20 pound per mmBtu of heat input.

4. If arch-fired, 0.18 pound per mmBtu of heat input.

5. If fluidized bed-fired, 0.15 pound per mmBtu of heat input.

NR 428.23 Demonstrating compliance with emission limitations. The owner or operator of an emissions unit shall determine the emissions unit's NO_x emissions and shall determine compliance with the emission limitations in s. NR 428.22 according to the applicable methods in this section.

(1) EMISSIONS MONITORING REQUIREMENTS. (a) *Installation and operation.* No later than April 1, 2009 or April 1 of the year an emissions unit first becomes subject to an emission limitation in s. NR. 428.22, the owner or operator of the emissions unit shall do the following:

1. Submit to the department in writing, a certification of the installation and operation of all monitoring systems or a certification of the completion of initial emission performance tests required under par. (b).

2. Begin and continue to monitor, measure and record all data necessary to determine emissions in the measurement units of the applicable emission limitation according to the methods of this section.

(b) *Monitoring systems and procedures.* 1. 'Part 75 continuous emissions monitoring.' The owner or operator of an affected unit as defined under s. NR 400.02(11), or an emissions unit subject to 40 CFR part 97 shall monitor NO_x emissions for requirements of this subsection by installing and operating monitoring equipment and measuring and recording NO_x emissions data according to methods and specifications of 40 CFR part 75 and 40 CFR part 75, Appendices A to I, incorporated by reference in s. NR 484.04(27) as required of an affected unit or an emissions unit subject to 40 CFR part 97.

2. 'Continuous emissions monitoring.' Except as provided in subd. 1., the owner or operator of an emissions unit subject to an emissions limitation in s. NR 428.22(1)(a) to (d) shall monitor NO_x emissions for requirements of this subsection according to the following specifications, as applicable:

a. The owner or operator shall install and operate a continuous emissions monitoring system that measures the hourly average NO_x emission rate.

b. The emissions monitoring system shall consist of an NO_x diluent continuous emissions analyzer and, as applicable, an O_2 or CO_2 diluent continuous emissions analyzer to correct all emissions data and heat rate values for the emissions unit to the same moisture and diluent gas basis, as required in subd. 6.b.

c. The owner or operator shall calibrate, maintain and operate the emissions monitoring system according to the requirements of s. NR 439.09(9), the applicable operating requirements of 40 CFR 60.13, the performance specifications in 40 CFR part 60, Appendix B, incorporated by reference in s. NR 484.04(21) and the quality assurance procedures of 40 CFR part 60, Appendix F, incorporated by reference in s. NR 484.04(21m).

d. For an emissions unit subject to an NO_x emission limit on a pound per million Btu basis, the emissions shall be determined using the F-factor method according to methods in Method 19 of 40 CFR part 60, Appendix A, incorporated by reference in s. NR 484.04(16m).

e. Except for an emissions unit subject to subd. 1. or an emissions unit subject to an emission limitation in s. NR 428.22(1)(a)1. to 4., an owner or operator of an emissions unit may measure NO_x emissions for compliance determination purposes using continuous parametric monitoring methods meeting emissions monitoring specifications in 40 CFR part 75, Appendix E, incorporated by reference in s. NR 484.04(26m)(cm).

3. 'Periodic emissions performance test.' Except as provided in subd. 1., the owner or operator of an emissions unit subject to s. NR 428.22(1)(e) to (i) shall conduct an initial performance test and a subsequent performance test every 2 years thereafter, according to the following requirements, as applicable, to determine the emissions unit's NO_x emission rate for each fuel fired in the emissions unit. A performance test is not required for a fuel used only for startup or for a fuel constituting less than 1% of the unit’s annual fuel consumption.

a. The emissions performance test shall be conducted according to one of the following methods as applicable: Method 7, 7A, 7B, 7C, 7D or 7E in 40 CFR part 60, Appendix A, incorporated by reference in s. NR 484.04(15m).

b. Except for units specified in this subd. 3.c., the initial emissions performance test shall include a determination of the capacity load point of the unit’s maximum NO_x emissions rate based on one 30 minute test run at each capacity load point for which the unit is operated, other than for startup and shutdown, in the load ranges of 20 to 30%, 45 to 55%, 70 to 80% and 90 to 100%.

c. The emissions performance tests for emissions units subject to s. NR 428.22(1)(g) or (h) shall be conducted within 10% of full load operation.

d. The emissions performance test shall determine compliance based on the average of 3 60-minute test runs performed at the capacity load specified in this subd. 3.b. or c.

e. An additional performance test shall be conducted according to this subd. 3.b. or c. within 90 days of completing an equipment modification or change in fuel which has the potential to increase the NO_x emissions concentration or rate.

4. 'Continuous monitoring for an output based standard.' In addition to applicable monitoring and measuring requirements under subd. 2., the owner or operator of an emissions unit subject to an output emission limitation in s. NR 428.22(1)(d) shall do the following:

a. Install, maintain and operate monitoring equipment for measuring and recording the output on an hourly basis with plus or minus 5% accuracy, in units consistent with the applicable emission limitation.

b. Calculate on an hourly basis, the output based emission rate as the hourly mass of NO_x emissions determined according to subd. 5. divided by the emissions unit's total output for that hour.

5. 'Continuous monitoring of total heat input and mass emissions.' The owner or operator of an emissions unit required to measure total heat input or mass NO_x emissions for requirements of subd. 4., sub. (2)(c) and s. NR 428.25(1)(b) or (c) shall perform the applicable measurements according to following:

a. Except as allowed in subd. 5.d., install, calibrate, maintain and operate a volumetric flue gas flow monitoring system meeting specifications in subd. 2.c. The hourly heat input shall be determined using the F-factor and the as fired fuel heat content according to Method 19 of 40 CFR part 60, Appendix A , incorporated by reference in s. NR 484.04(16m).

b. Unless specified in Method 19 of 40 CFR part 60, Appendix A, incorporated by reference in s. NR 484.04(16m), the heat content value for each fuel shall be based on a heat content analysis.

c. The mass of NO_x emissions shall be determined on an hourly basis by either multiplying the NO_x concentration by the flue gas flow rate corrected for diluent gas and moisture or, by multiplying the monitored hourly average emission rate in mass per mmBtu by the total heat input as determined under subd. 5.a. or b. The calculations of mass emissions are to be performed according to conversion procedures in 40 CFR part 75, Appendix F, incorporated by reference in s. NR 484.04(26m)(d).

d. For a liquid or gaseous fuel fired system, the total heat input and mass of NO_x emissions may be determined using a fuel flow monitoring system capable of determining the hourly flow with plus or minus 5% accurancy and using continuous parametric monitoring as specified under subd. 8. The total heat input shall be calculated as the total fuel flow multiplied by the fuel heat content.

6. 'General monitoring requirements.' Unless otherwise specified in this subsection, an owner or operator shall meet the following requirements:

a. All certification tests or emissions performance tests shall be performed according to procedures of s. NR 439.07.

b. The determination of emission rates, mass emissions and total heat input shall be calculated and corrected to the same basis for flue gas moisture and diluent gases according to Method 19 of 40 CFR part 60, Appendix A, incorporated by reference in s. NR 484.04 (16m) or 40 CFR part 75, Appendix F, incorporated by reference in s. NR 484.04(26m)(d).

c. For emissions units with a common flue gas stack system, all sampling locations and apportionment of emissions to an individual emissions unit shall conform to applicable procedures and methods in 40 CFR part 75, Appendix F, incorporated by reference in s. NR 484.04(26m)(d).

7. 'Malfunction and abatement.' An owner or operator of an emissions unit subject to the malfunction and abatement plan requirement of s. NR 439.11 shall include a malfunction plan for the emissions monitoring system and a monitoring and operating plan for continuing operation of the

emissions unit in a manner consistent with meeting all applicable emission limitations during any period when the monitoring system malfunctions or is inoperable other than for scheduled maintenance.

8. 'Alternate emissions monitoring.' An owner or operator of an emissions unit may request and monitor NO_x emissions for compliance determination purposes using an equivalent alternative method to any requirement of this subsection with written approval of the department and the administrator.

(2) COMPILATION OF EMISSIONS. An owner or operator shall compile the measured emissions data in measurement units consistent with the units of the applicable emission limitation according to the following applicable calculation and tabulation methods for purposes of demonstrating compliance:

(a) *Continuous emissions monitoring*. When measuring emissions according to requirements in sub. (1)(b)1. or 2.:

1. The average emission rate shall be the average of the hourly average emissions obtained from the continuous emissions monitoring system for the hours the emissions unit operated during the averaging period. The calculation is as follows:

$$E_A = \left(\frac{1}{n}\right)\sum_{j=1}^{n} E_{H,j} \quad \text{Equation 2}$$

where:

E_A is the average emission rate for the compliance period in units consistent with units of the applicable emission limit

$E_{H,j}$ is the hourly average emission rate for each hour, j, for which the emissions unit is operating during the compliance period in units consistent with units of the applicable emission limit

n is the total number of hours the emissions unit operated during the compliance period

2. The 30-day rolling period shall consist of the day of monitoring and the previous 29 consecutive calendar days. A new 30-day rolling average emission rate (E_A) shall be calculated and recorded at the end of each day.

(b) *Emissions performance testing*. When measuring emissions according to performance testing requirements of sub. (1)(b)3., the 30-day rolling average emission rate or concentration shall be the emissions determined in sub. (1)(b)3.d. for the most recent performance test.

(c) *Multiple fuel-fired emissions units.* When measuring emissions for an emissions unit firing multiple fuels, compliance shall be determined according to one of the following methods:

1. The unit's emissions shall be monitored and compiled according to applicable methods in par. (a) or (b) for each individual fuel and compliance demonstrated with the emission limitation for each fuel.

2. The unit's emissions and a multiple fuel emission limit shall be determined on a total heat input fuel weighted basis according to equation 3. A fuel representing less than 1% of the unit's annual fuel consumption on a heat input basis may be excluded in determining the multiple fuel emission limit.

$$E_{HIWieghted} = \frac{\sum_{f=1}^{n} E_f HI_f}{\sum_{f=1}^{n} HI_f} \qquad \text{Equation 3}$$

where:

$E_{HIWeighted}$ is the heat input weighted multiple fuel emission rate or emission limitation for the compliance period in units consistent with the units of the emission limitation

E_f is the emission rate or emission limit for fuel F during the compliance period in units consistent with the units of the emission limitation

HI_f is the total heat input for fuel F during the compliance period

n is the number of different fuels used during the compliance period

(d) *Total heat input and mass emissions*. When measuring hourly heat input or mass of NO_x emissions according to sub. (1)(b)5., the totals over a period of time shall be compiled according to the following procedures:

1. The total hourly heat input shall be summed for the hours the emissions unit operated during the applicable period of time according to equation 4.

$$HI_{total} = \sum_{h=1}^{n} HI_h \quad \text{Equation 4}$$

where:

HI_{total} is the total heat input by fuel over the period of time

HI_{jh} is the heat input by fuel for hour h

n is the number of hours over which the specific fuel was burned

2. The total hourly mass of NO_x emissions shall be summed for the hours the emissions unit operated during the applicable period of time according to equation 5.

$$NO_x\ Mass_{total} = \sum_{h=1}^{n} Mass_h \quad \text{Equation 5}$$

where:

$NO_x\ Mass_{total}$ is the total mass of NO_x emissions over the period of time

$Mass_h$ is the mass of NO_x emissions for hour h

n is the number of hours the emissions unit is operating during the specified period of time

NR 428.24 Recordkeeping and reporting. (1) EMISSION LIMITATIONS. The owner or operator of an emissions unit subject to an emission limitation in s. NR 428.22 shall meet the recordkeeping and reporting requirements of this subsection.

(a) *Recordkeeping.* In addition to the recordkeeping requirements of ss. NR 439.04(1) and (2) and 439.05, the owner or operator shall maintain records of all of the following:

1. The applicable emission limit and calculated heat input weighted emission limit for an emissions unit demonstrating compliance for multiple fuels.

2. The 30-day rolling average emission rate on a daily basis determined according to s. NR 428.23.

3. The total monthly heat input for each fuel or the emissions unit output, as applicable, in measurement units consistent with the units of the applicable emission limitation.

4. The emissions unit's annual and ozone season capacity utilization in measurement units consistent with the units of the applicable emission limitation.

5. For the emissions monitoring system required in s. NR 428.23(1)(b) on an annual and on an ozone season basis, records of performed maintenance, hours of malfunction and necessary repairs, and the percent of hours the monitoring system operated during the emissions unit's operating hours.

(b) *Reporting.* In the reports to the department required under s. NR 439.03(1)(b), the owner or operator shall submit the following information:

1. A certification of compliance with the applicable emission limitation in s. NR 428.22 or identification of the periods of non-compliance, with a quantification of the excess emission rate and the excess mass emissions.

2. For each calendar month, the highest 30-day rolling average emission rate. The emissions data shall be reported in the measurement units of the applicable emission limitation.

3. The emissions unit's annual and ozone season total operating hours, capacity utilization, and the percent operation of any required continuous emissions or combustion monitoring systems during the hours the emissions unit was operating.

(2) GENERAL EXEMPTION UNIT. The owner or operator of an emissions unit claiming exemption under s. NR 428.21, shall record operational parameters necessary to demonstrate the unit's qualification for the exemption status.

(3) LOW OPERATING UNIT. The owner or operator claiming a low operating unit exemption for an emissions unit under s. NR 428.21(2), shall maintain a record of the unit's applicable fuel heat input or production output, as applicable, the unit's total capacity utilization on an ozone season and on an annual basis for each calendar year and calculations demonstrating the unit's qualification for the exemption.

(4) OTHER REGULATED UNIT. The owner or operator claiming a regulated emissions unit exemption for an emissions unit under s. NR 428.21(2), shall maintain a record of all performance tests, calculations, assumptions and methods used to determine the emissions unit's potential emissions.

NR 428.25 Alternative compliance methods and approaches. (1) EMISSIONS AVERAGING. The owner or operator of an emissions unit may demonstrate compliance with an NO_x emission limitation in s. NR 428.22 by participating in an emissions rate averaging program according to the general provisions of par. (a) and either the specifications for facility wide averaging in par. (b) or for multi-facility averaging in par. (c).

(a) *General provisions.* 1. 'Participating units.' a. The participation of an emissions unit in an emissions averaging program shall be designated for a full calendar year. Individual emissions units may not be withdrawn from an averaging program, during a year, unless each emissions unit in the averaging program meets its applicable emission limit in s. NR 428.22.

b. If an emissions unit at a facility participates in an averaging program, all similar units at the facility shall be included in the averaging program unless the unit is complying with an emission limit in s. NR 428.22 or is participating in another emissions averaging program under this subsection. Similar

units at a facility are those which serve a similar process or purpose and which are described by the same general source category under s. NR 428.22 without regard to fuel type or unit size threshold.

c. An emissions unit for which the department has approved an alternative emission limit or compliance schedule under sub. (3) may not participate in an emissions averaging program under this subsection.

2. 'Monitoring requirement.' The owner or operator of an emissions unit participating in an emissions averaging program shall monitor all necessary NO_x emissions, as applicable, according to requirements of s. NR 428.23(1)(b)1. or 2. The total heat input and NO_x mass emissions shall be monitored and measured according to s. NR 428.23(1)(b)5. and compiled according to s. NR 428.23(2)(d).

3. 'New units'. An emissions unit which begins operation on or after the effective date of this section… [revisor insert date] may not participate in an emissions averaging program under this subsection.

4. 'Emission reductions.' For purposes of this subsection, only emission reductions which go beyond all state and federal requirements are considered excess emission reductions.

(b) *Facility averaging*. An owner or operator may average emissions from emissions units at one facility by complying with the following procedures for demonstrating compliance on an annual and on an ozone season basis with an aggregate NO_x emission limit and mass emissions cap:

1. 'Notification.' The owner or operator shall submit to the department a notification of an NO_x emissions averaging program by October 1 of the year prior to the emissions averaging year. The notification shall include the following information:

a. The participating emissions units.

b. The owner or operator of each emissions unit.

c. For a unit subject to s. NR 428.22, the applicable emission limitation.

d. For a participating emissions unit not subject to s. NR 428.22, the average emission rate by fuel type over the unit's normal operating range determined according to methods of s. NR 428.23(1)(b)3. The tested average emission rate may be adjusted based on a heat input weighted average of the emissions unit's annual percent operation at different load points in the previous calendar year.

e. For averaging programs effective on or after January 1, 2013, for each emissions unit, the annual and ozone season heat input for 2000 to 2005, and the annual and ozone season average of the 3 years of highest annual heat input for 2000 to 2005.

f. For averaging programs effective on or after January 1, 2013, an annual and ozone season NO_x mass emissions cap in aggregate for the emissions units in the averaging program. The mass emissions caps shall be the summation of the products for each emissions unit of the emission limitation in subd. 1.c. or the average emission rate in subd. 1.d. and the 3-year average annual or ozone season heat input. The mass emission cap shall be calculated as follows:

$$MC = \sum_{i=1}^{n} \left[\sum_{j=1}^{k} E_j HI_j \right]_i \qquad \text{Equation 6}$$

where:

MC is either the annual mass emissions cap or the ozone season mass emissions cap in tons of NO_x for all units participating in the averaging program

E_j is the applicable emission limitation for fuel j submitted in subd. 1.c. or the average emission rate in subd. 1.d.

HI_j is either the average annual or ozone season heat input for fuel j, submitted in subd. 1.e., for the 3 years of highest heat input from 2000 to 2005

k is the number of fuels fired by a unit either during the year or during the ozone season

n is the number of units participating in the averaging program

2. 'Implementation.' The department shall review the proposed averaging program provided in the notification and unless the department, within 30 days of receiving the proposed averaging program, requests additional information or revisions to the program, the owner or operator shall comply with the submitted emissions averaging program.

3. 'Compliance demonstration.' The owner or operator of emissions units participating in the averaging program shall submit a compliance report containing the following information by March 1 of the calendar year following the averaging program year:

a. The annual and ozone season actual heat input by fuel type for each emissions unit in the averaging program.

b. The annual and ozone season actual NO_x mass emissions for each emissions unit.

c. The annual and ozone season actual average NO_x emission rate for each emissions unit calculated as follows:

$$ER_{avg} = \frac{NO_x \text{ Mass}}{\sum_{j=1}^{n} HI_j} \qquad \text{Equation 7}$$

where:

ER_{avg} is the annual or ozone season average emission rate for each emissions unit

NO_x Mass is the total NO_x mass emissions for the averaging period

HI_j is the heat input for fuel type j for the averaging period

n is the number of fuels fired during the averaging period

d. The annual and ozone season actual NO_x mass emissions and heat input in aggregate for all emissions units.

e. The annual and ozone season actual aggregate NO_x emission rate for all emissions units. This emission rate is the summation of the total mass of NO_x emissions for all emissions units divided by the total heat input for all emissions units and is calculated as follows:

$$ER_{aggr} = \frac{\sum_{u=1}^{n} NO_x \ Mass_u}{\sum_{u=1}^{n} HI_u} \qquad \text{Equation 8}$$

where:

ER_{aggr} is the emission rate in aggregate for all emissions units on an annual or ozone season basis

$NO_x \ Mass_u$ is the total NO_x mass emissions for emissions unit u, for the averaging period

HI_u is the total heat input for each emissions unit u, for the averaging period

n is the number of emissions units participating in averaging

f. The annual and ozone season aggregate emission limitation for all emissions units. These emission limitations are the summation of the product of each unit's actual heat input and emission limitation by fuel type divided by the summation of the actual heat input for all emissions units. The aggregate emission limitations shall be calculated as follows:

$$EL_{aggr} = \frac{\sum_{u=1}^{n} \left(\sum_{f=1}^{j} HI_f EL_f \right)}{\sum_{u=1}^{n} HI_u} \qquad \text{Equation 9}$$

where:

EL_{aggr} is the aggregate emission limit for all emissions units on an annual or ozone season basis

HI_f is the heat input for fuel f, for unit u

EL_f is the emission limit for fuel f, for unit u

HI_u is the total heat input for emissions unit u, for the averaging period

n is the number of emissions units participating in averaging

f is the number of fuels for unit u

g. Compliance on an annual and ozone season basis is demonstrated if the aggregate emission rate required in subd. 3.e. is less than the aggregate emission limit required in subd. 3.f., and the NO_x mass emissions required in subd. 3.b. is less than the mass emissions cap required in subd. 1.f.

4. 'Heat input conversion.' For an emissions unit subject to emission limitations expressed in units other than heat input, the emission limitation shall be converted to a heat input basis. All required calculations shall be on a common basis with necessary conversions performed according to the methods in 40 CFR part 60, Appendices A and B, incorporated by reference in s. NR 484.04(13) and (21).

5. 'Mass emissions cap exceedance.' If the total NOx emissions from the emissions units in the averaging program exceed either the annual or ozone season emissions caps determined in subd. 1.f., the owner or operator shall achieve additional NO_x reductions to compensate for the excess emissions within 3 calendar years after the averaging year with the exceedance.

(c) *Multi-facility average.* An owner or operator may average emissions from emissions units at multiple facilities by complying with the following procedures for demonstrating compliance on an annual and ozone season basis with an aggregate NO_x emission limitation:

1. 'Notification.' The owner or operator shall submit to the department a notification of an NO_x emissions averaging program by October 1 of the year prior to the emissions averaging year. The notification shall include the following information:

a. The participating emissions units.

b. The owner or operator of each emissions unit.

c. The applicable emission limitation in s. NR 428.22 for each emissions unit.

d. The projected heat input, capacity utilization, NO_x emission rate and total NO_x mass emissions

for each emissions unit on an annual and ozone season basis.

e. The projected heat input, capacity utilization, NO_x emission rate and total NO_x mass emissions in aggregate for all emissions units participating in the averaging program.

2. 'Implementation.' The department shall review the proposed averaging program provided in the notification and unless the department, within 30 days of receiving the proposed averaging program, requests additional information or revisions to the program, the owner or operator shall comply with the submitted emissions averaging program.

3. 'Public notice.' a. The owner or operator proposing to average emissions units at multiple facilities shall provide public notice 60 days prior to the calendar year of the averaging program in newspapers of general circulation for the areas of the emissions units.

b. The public notice shall describe the proposed averaging program, the participating emissions units and how to obtain a copy of the averaging program information required in subd. 1.

c. In addition to the information required in subd. 1., the averaging program information provided to the public upon request shall indicate whether any of the emissions units identified in the proposed averaging program participated in prior averaging programs under this subsection and whether that participation resulted in a violation of the emission limits.

4. 'Compliance demonstration.' The owner or operator participating in an averaging program shall submit a compliance report containing the following information by March 1 of the calendar year following the averaging program year:

a. The annual and ozone season actual heat input for each emissions unit.

b. The annual and ozone season actual NO_x mass emissions for each emissions unit.

c. The annual and ozone season actual average NO_x emission rate for each emissions unit calculated using Equation 7 in par. (b)3.c.

d. The annual and ozone season actual NO_x mass emissions and heat input in aggregate for all emissions units.

e. The annual and ozone season aggregate NO_x emission rate for all emissions units calculated using Equation 8 in par. (b)3.e.

f. The annual and ozone season aggregate emission limitation for all emissions units. These emission limitations are the summation of the product of the each unit's actual heat input and emission limitation divided by the summed actual heat input for all emissions units less an averaging program environmental benefit factor. The aggregate emission limitations are calculated as follows:

$$EL_{aggr} = \frac{\sum_{u=1}^{n} HI_u EL_u}{\sum_{u=1}^{n} HI_u} x(1 - EBF) \qquad \text{Equation 10}$$

where:

EL_{aggr} is the aggregate emission limit in aggregate for all emissions units on an annual or ozone season basis

HI_u is the heat input for each emissions unit, u, for the specified period of time

EL_u is the emission limit for each emissions unit, u. For emission limitations in units other than heat input, the emission limitations shall be converted to a heat input basis according to sub. (b)4.

EBF is the environmental benefit factor. For averaging programs effective on or after January 1, 2013, the EBF is 10% for the annual emission limit and 10% for the ozone season emission limit. Prior to this date the EBF is 0%.

g. A demonstration of compliance on an annual and ozone season basis consisting of the aggregate emission rates under subd. 4.e. compared to the aggregate emission limitations calculated in subd. 4.f.

(d) *Violations and penalties*. 1. All emissions units participating in an emissions averaging program are considered out of compliance if emissions exceed any of the averaging program emission limitations on either an annual or ozone season basis.

2. Each emissions unit participating in the averaging program shall be considered in violation for each day of non-compliance until corrective action is taken to achieve compliance.

3. Except for those periods of time for which the department grants an electric or steam utility reliability waiver under s. NR 428.28 to the emissions units exceeding the applicable aggregate average emission limitation, the department shall require the owners or operators of the emissions units in the program to achieve reductions equivalent to the amount of the exceedance. The additional emission reductions shall be achieved within the subsequent 3 years on an annual or ozone season basis, consistent with the period of the exceedance.

4. All owners or operators of emissions units considered out of compliance with an averaging program emission limitation are liable for each violation and subject to enforcement and penalty provisions under ss. 285.83 and 285.87, Stats. The owners or operators of the emissions units in the averaging plan shall evaluate the emissions and operating data for any period of non-compliance to determine which units is responsible for the non-compliance event. The information used in this evaluation shall be made available to the department within 30 days of the discovery of a non-compliance event.

5. The parameters required in the notice under par. (c) 1.d. shall constitute annual and ozone season alternative compliance limits for each unit participating in a multi-facility averaging program

under par. (c). If compliance is demonstrated under par. (c)4.g., all emissions units in the averaging program shall be deemed to be in compliance with the alternative compliance limits.

(2) CAIR EMISSIONS UNITS. The owner or operator of an emissions unit which is subject to the emission reduction requirements of the clean air interstate rule (CAIR) under 40 CFR part 97 may demonstrate that the NO_x emission reductions achieved by the emissions unit in complying with the CAIR requirements constitute compliance with the NO_x RACT emission limitation requirements of this subchapter.

(3) ALTERNATIVE RACT REQUIREMENT. (a) The owner or operator of an emissions unit may request that the department establish an alternative emission limitation or alternative compliance deadline to the requirements in s. NR 428.22 if the owner or operator demonstrates that it is economically or technically infeasible to meet the requirement.

(b) The owner or operator of the emissions unit shall submit the request with the demonstration for an alternative RACT requirement by the later of May 1, 2008 or by May 1 following the calendar year in which an emissions unit first becomes subject to an emission limitation in s. NR 428.22.

(c) Any request for an alternative RACT requirement made under this subsection shall be subject to the requirements and procedures of s. NR 436.05 and written approval of the administrator.

NR 428.26 Utility reliability waiver. The owner or operator of an emissions unit used for purposes of electric or steam utility generation or natural gas utility transmission and subject to an emission limitation in s. NR 428.22 may request that the department grant a waiver from meeting the emission limitation for a specific period of time based on the following criteria and procedures:

(1) The waiver request is due to the utility's need to maintain a supply of electricity, steam, or natural gas to non-interruptible customers.

(2) A waiver request may only be based on an unavoidable or unforeseeable event including:

(a) A major electric supply event affecting the utility.

(b) A major fuel supply disruption affecting the utility.

(c) A disruption in the operation of a generating unit or pollution control equipment.

(3) The owner or operator of a utility shall submit a written request for a waiver that provides information sufficient to demonstrate to the department's satisfaction that granting the waiver is warranted. The request shall include the following:

(a) The duration of the conditions warranting the waiver.

(b) The specific measures taken to mitigate emissions during the duration for which the waiver is requested.

(c) The reasons why the utility was unable to achieve compliance with the emission requirement.

(4) The department may grant a waiver under this section if, in consultation with the public service commission and written approval by the administrator, the department determines that the owner or operator's failure to meet a requirement under s. NR 428.22 is consistent with criteria of sub. (2).

(5) Within 60 days after the receipt of a complete request, the department shall publish a public notice of the receipt of the waiver request and the department's preliminary determination to approve, partially approve, or deny the request. The department shall provide an opportunity for public comments on the request and the department's preliminary determination. The department shall hold a public hearing on the request if a hearing is requested by a person affected by the waiver request.

(6) Following the public comment period, the department shall notify the applicant in writing of the final determination to approve, conditionally approve or deny the waiver request.

SECTION 5. NR 484.04(13) is amended to read:

CFR Appendix Referenced		Title	Incorporated by Reference For
NR 484.04			
(13)	40 CFR part 60 Appendix A	Test Methods	NR 400.02(131)

			NR 428.25(1)(b)4. NR 439 NR 460 to 469

SECTION 6. NR 484.04(15m) and (16m) are created to read:

	CFR Appendix Referenced	Title	Incorporated by Reference For
NR 484.04			
(15m)	40 CFR part 60 Appendix A, Method 7, 7A, 7B, 7C, 7D and 7E	Determination of nitrogen oxide emissions from stationary sources	NR 428.23(1)(b)3.a.
(16m)	40 CFR part 60 Appendix A, Method 19	Determination of sulfur dioxide removal efficiency and particulate, sulfur dioxide and nitrogen oxides emission rates	NR 428.23(1)(b)2.d., 5.a. and b. and 6.b.

SECTION 7. NR 484.04(21m) is amended to read:

	CFR Appendix Referenced	Title	Incorporated by Reference For
NR 484.04			
(21m)	40 CFR part 60 Appendix F	Quality Assurance Procedures	NR 428.23(1)(b)2.c. NR 466.10(2)

SECTION 8. NR 484.04(26m)(bm) is created to read:

	CFR Appendix Referenced	Title	Incorporated by Reference For
NR 484.04			
(26m)(bm)	40 CFR part 75 Appendix E	Optional NO_x Emissions Estimation Protocol for Gas-Fired Peaking Units and Oil-Fired Peaking Units	NR 428.23(1)(b)2.e.

SECTION 9. NR 484.04(26m)(d) and (27) are amended to read:

	CFR Appendix Referenced	Title	Incorporated by Reference For
NR 484.04			
(26m)(d)	40 CFR part 75 Appendix F	Conversion Procedures	NR 428.23(1)(b)5.c. and

		6.b. and c. NR 446.04(3) NR 446.09(1)(a)
(27)	40 CFR part 75 Appendices A to I	NR 428 NR 439 NR 428.23(1)(b)1.

SECTION 10. EFFECTIVE DATE. This rule shall take effect on the first day of the month following publication in the Wisconsin administrative register as provided in s. 227.22 (2) (intro.), Stats.

SECTION 11. BOARD ADOPTION. This rule was approved and adopted by the State of Wisconsin Natural Resources Board on _____.

Dated at Madison, Wisconsin _____.

STATE OF WISCONSIN
DEPARTMENT OF NATURAL RESOURCES

By_____
Scott Hassett, Secretary

(SEAL)