TECHNICAL SUPPORT DOCUMENT
FOR
CONTROLLING NOx EMISSIONS
FROM
STATIONARY RECIPROCATING INTERNAL COMBUSTION ENGINES AND TURBINES

AQPSTR 07-01

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List of Acronyms

A/F	air-to-fuel
ACT	Alternative Control Techniques document
ALAPCO	Association of Local Air Pollution Control Officials
BART	Best Available Retrofit Technology
bhp	brake horsepower
Board	Illinois Pollution Control Board
BOOS	burner out of service
Btu	British Thermal Unit
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CO	carbon monoxide
CO_2	carbon dioxide
CPI	Consumer Price Index
CT	combustion tuning
EE	energy efficiency
EGU	electric generating unit
FIP	Federal Implementation Plan
HC	hydrocarbons
Illinois EPA	Illinois Environmental Protection Agency
ITR	ignition timing retard
Lb	pound
LADCO	Lake Michigan Air Directors' Consortium
LEC	low emission combustion
mmBtu	million British Thermal Units
MW	megawatt
NAA	nonattainment area
NAAQS	National Ambient Air Quality Standards
NOx	nitrogen oxide
O_2	oxygen
O_3	ozone
$PM_{2.5}$	fine particulate matter
ppm	parts per million
ppmv	parts per million by volume
PSC	prestratified charge
PTE	potential to emit
RACT	Reasonably Available Control Technology
RFP	Reasonable Further Progress
RIA	Regulatory Impact Analysis
RICE	stationary reciprocating internal combustion engine
SCR	selective catalytic reduction
SI	spark-ignited
SIP	State Implementation Plan
SNCR	selective non-catalytic reduction
SO_2	sulfur dioxide
STAPPA	State and Territorial Air Pollution Program

TSD	Technical Support Document
TPY	tons per year
VOM	volatile organic material
ug/m^3	microgram per cubic meter
U.S. EPA	United States Environmental Protection Agency

Executive Summary

This technical support document (TSD) presents the rationale, documentation, and methodology developed by the Illinois Environmental Protection Agency (Illinois EPA) in support of its proposed regulation to control nitrogen oxide (NOx) emissions from stationary reciprocating internal combustion engines (RICE) and turbines. Reciprocating internal combustion engines and turbines are a significant source category of NOx emissions in Illinois and a contributor to fine particulate matter ($PM_{2.5}$) and ozone levels in areas of Illinois that are designated as nonattainment areas (NAAs) for these pollutants. Air quality modeling performed by the United States Environmental Protection Agency (U.S. EPA) and by the Lake Michigan Air Directors' Consortium (LADCO) indicates that control of NOx emissions are necessary for the State of Illinois to attain the National Ambient Air Quality Standards (NAAQS) for 8-hour ozone (62 *FR* 38885) and $PM_{2.5}$ (62 *FR* 38652).[1, 2] This regulatory proposal is intended to satisfy, in part, Illinois' obligation under the Clean Air Act (CAA) to develop a State Implementation Plan (SIP) to comply with the NAAQS.

On April 21, 2004, U.S. EPA issued the final NOx SIP Call that required large RICE that emit more than one ton per day of NOx emissions during the ozone season to reduce their NOx emissions by 82 to 90 percent relative to 1995 levels. This regulatory proposal, if adopted, will satisfy this federal requirement. This proposal is also intended to address, in part, the requirement for Reasonably Available Control Technology (RACT) for NOx in 8-hour ozone and $PM_{2.5}$ nonattainment areas (NAAs). The Illinois EPA intends to address RACT requirements for other source categories in a separate rulemaking. This proposal will also address, in part, federal requirements to achieve emission reductions needed to ensure Reasonable Further Progress (RFP) toward attainment of the NAAQS.

Illinois EPA is proposing to control NOx emissions from sources that have a potential to emit (PTE) of 100 tons per year (TPY) of NOx, aggregated from all the affected units at the source. Regulations to control NOx emissions from RICE down to 500 brake-horsepower (bhp) and turbines down to 3.5 megawatts (MW) that are not regulated under other existing or proposed NOx regulations are included in this proposal. The proposed regulation does not apply to

emergency standby engines; engines used in research and testing for the purposes of performance verification of engines; engines/turbines regulated under Subpart W of 35 Ill. Adm. Code; engines/turbines used for agricultural purpose; and certain portable engines. Illinois EPA, in consultation with the affected sources, is proposing a low-usage limit of 8 million bhp-hour per year, aggregated from all affected engines at a source, and 20 thousand MW-hour per year, aggregated from all affected turbines at a source.

The statewide NOx control levels proposed in this submittal are considered reasonable, attainable, and cost-effective. The NOx emissions levels are prescribed in parts per million by volume (ppmv) corrected to 15 percent oxygen (O_2) on a dry basis. The NOx limits for engines are 150 ppmv for spark-ignited rich-burn; 210 ppmv for spark-ignited lean-burn; 365 ppmv for Worthington engines; and 660 ppmv for diesel engines. For turbines, the NOx limits are 42 ppmv for gas-fired, and 96 ppmv for liquid-fired turbines. An owner or operator may comply with the control requirements by averaging the emissions of affected units. Compliance with the emission limits will be determined on both an ozone season (May 1 to September 30) and an annual (January 1 to December 31) basis each year.

This proposal requires the owner or operator of large engines that emit more than 1 ton of NOx per summer day to reduce the emissions from those engines by 82 percent by the beginning of the 2007 ozone control season (by May 1, 2007). It also requires that each stationary internal combustion engine of 500 bhp capacity and above, and each stationary turbine of capacity equal to or greater than 3.5 MW be controlled to prescribed standards and by specified compliance dates based on the size and geographical location of the affected unit.

The Illinois EPA relied on the cost data and cost effectiveness estimates contained in the U.S. EPA's TSDs for the NOx SIP Call, alternative control technology (ACT) guidance documents prepared by the U.S EPA for RICE and turbines, and the U.S. EPA's AirControlNET cost analysis model. The proposed regulations will reduce NOx emissions by 5,422 tons per ozone season in the 2007 ozone control season and satisfy the U.S. EPA's NOx SIP Call Phase II requirements for impacted RICE. In addition, the proposed regulation will potentially affect a total of 202 RICE (including engines affected by the NOx SIP Call) and 36 turbines in Illinois.

When fully implemented, NOx emissions will be reduced statewide by approximately 17,082 TPY and 7,206 tons per ozone control season. This equates to NOx reductions from this source category of approximately 65 percent on an annual basis, and 55 percent in the ozone season.

1.0 Introduction

This TSD presents the rationale, documentation, and methodology developed by the Illinois EPA to support its proposed regulation to control NOx emissions from RICE and turbines. RICE and turbines are significant sources of NOx emissions in Illinois. Based on the Illinois EPA's 2002 base year emissions inventory, out of 277,899 TPY of NOx emissions from point sources in Illinois, approximately 23,347 TPY of NOx were emitted from RICE and turbines. This represents approximately 8.4 percent of Illinois' total point source NOx emissions.

Illinois has the responsibility under the CAA to develop a State Implementation Plan (SIP) which provides the emissions reductions needed to attain the NAAQS for ozone and $PM_{2.5}$. Air quality modeling performed by U.S. EPA and LADCO indicates that control of NOx emissions is necessary for the State of Illinois to comply with the NAAQS for 8-hour ozone [1] and $PM_{2.5}$.[2] The statewide NOx emissions reductions which will be achieved by implementation of this proposal are a necessary component of Illinois' plan to attain the NAAQS.

This proposal is an element of Illinois EPA's plan to meet the NAAQS, but it is intended to address other federal requirements as well. As will be discussed later in this report, the proposal is intended to address the requirements of U.S. EPA's Phase II of the NOx SIP Call affecting large RICE. This proposal is also intended to address, in part, the requirement for RACT for NOx in 8-hour ozone and $PM_{2.5}$ NAAs. The Illinois EPA intends to address RACT requirements for other source categories in a separate rulemaking. This proposal will also address, in part, federal requirements to achieve emission reductions needed to ensure RFP toward attainment of the NAAQS.

A brief summary of the various sections in this TSD is as follows:

Section 2 provides background information on ozone and particulate matter air quality and the effects of these pollutants on human health. The regulatory requirements that are being addressed by this proposal are also described in Section 2. National and regional air quality modeling analyses demonstrating the effectiveness of local and regional NOx emission reductions on improving air quality are also presented.

Section 3 contains descriptions of the various types of internal combustion engines and turbines and how NOx emissions are generated by these processes. Also presented in this Section are the estimated uncontrolled levels of NOx emissions from RICE and turbines in Illinois.

Section 4 identifies control techniques available to reduce NOx emissions from RICE and turbines.

General cost information on various control technologies is discussed in Section 5. This Section provides cost information for the various control technologies that are available to control NOx emissions from stationary RICE and turbines, described in terms of cost effectiveness of controls (i.e., dollars per ton of NOx emission reduced) to comply with the proposed regulation.

Existing and proposed regulations are discussed in Section 6. This Section summarizes the existing Illinois NOx regulations, and other states' NOx regulations for RICE and turbines, and concludes with an explanation of the proposed regulations.

Sources in Illinois that are potentially affected by the proposed regulations are listed in Section 7. Also described in this Section is the methodology that Illinois EPA used to identify sources that may potentially be affected by the proposed regulations.

Section 8 provides an estimate of emissions reductions that will be achieved by implementing the Illinois EPA's proposal and explains the methodology used by Illinois EPA to estimate NOx emissions reductions from this proposal.

Finally, a summary of this TSD is provided in Section 9.

2.0 Background

2.1 National Ambient Air Quality Standards for Ozone and Fine Particulates

The U.S. EPA revised the NAAQS for particulate matter and ozone in 1997.[1, 2] The revised standards for particulate matter recognized that the smallest particles, those less than equal to 2.5 microns in diameter, have adverse health effects in the humans. In response to the establishment of the NAAQS for $PM_{2.5}$, U.S. EPA designated two areas in Illinois as NAAs: the Chicago area (consisting of Cook, DuPage, Kane, Lake, McHenry, and Will counties, and the townships of Oswego, in Kendall County, and Aux Sable and Goose Lake, in Grundy County), and the Metro-East St. Louis area (consisting of Madison, Monroe, and St. Clair counties, and Baldwin Township in Randolph County). Figure 2-1 shows the $PM_{2.5}$ NAAs for Illinois and nearby states. These designations became effective on April 5, 2005 (70 *FR* 943).[26]

The revised NAAQS for ozone replaced the previous 1-hour averaging time with an 8-hour averaging time, and reduced the applicable ambient concentration threshold from 0.12 parts per million (ppm) to 0.08 ppm. U.S. EPA designated certain areas in Illinois and other states as nonattainment for this air quality standard. Figure 2-2 shows the 8-hour ozone NAAs for the states in the central U.S. These designations became effective on June 15, 2004 (69 *FR* 23858).[27] Geographically, the ozone NAAs in Illinois are roughly the same areas that were designated as nonattainment for $PM_{2.5}$. The exception is in the Metro-East area. The 8-hour ozone NAA includes Jersey County and does not include Baldwin Township in Randolph County, while the $PM_{2.5}$ NAA does not.

Fine particles and ozone are associated with thousands of premature deaths and illnesses each year in the United States. In revising the NAAQS for particulate matter, U.S. EPA found that fine particles aggravate respiratory, lung, and cardiovascular diseases, decrease lung function, and increase asthma attacks, heart attacks, and cardiac arrhythmia. As a consequence of exposure to $PM_{2.5}$, hospital admissions and emergency room visits increase as does absenteeism from school and work. Older adults, people with heart and lung disease, and children are the segments of society that are particularly sensitive to fine particle exposure. Attainment of the $PM_{2.5}$ standard will prolong thousands of lives in Illinois and other states. Additional information on the health effects of fine particles can be found on U.S. EPA's website at http://www.epa.gov/ttn/naaqs/standards/pm/s_pm_index.html.

Figure 2-1

$PM_{2.5}$ Nonattainment Areas

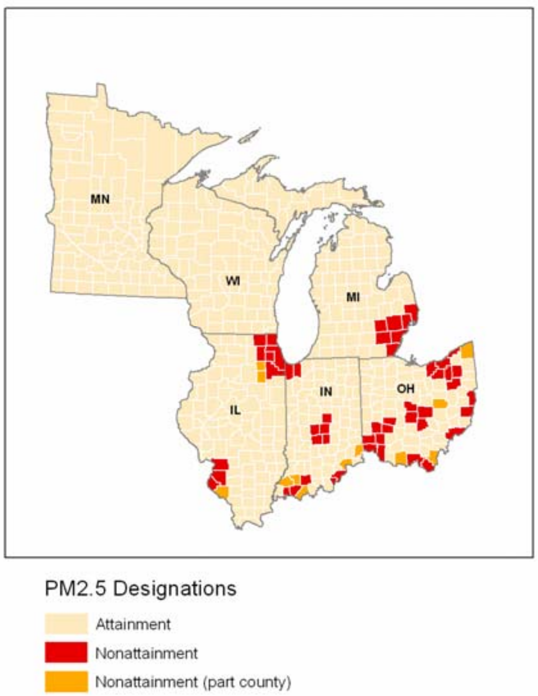
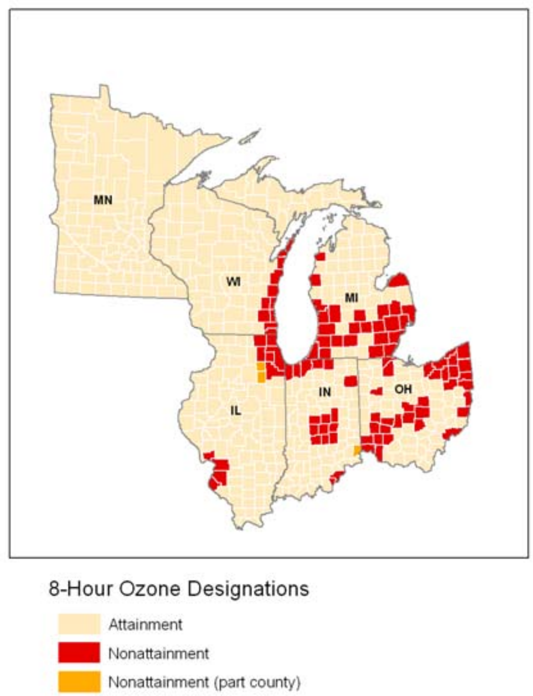


Figure 2-2

8-Hour Ozone Nonattainment Areas



U.S. EPA's revised NAAQS for ozone was intended to provide increased protection to the public, especially children and other at-risk populations, against a wide range of ozone-induced health effects. In setting the 8-hour ozone standard, U.S. EPA found that exposures to ozone of one to three hours in length had been found to irritate the respiratory system, causing coughing, throat irritation, and chest pain. Ozone exposure can limit lung function and breathing capacity, resulting in rapid and shallow breathing, thereby lowering or curtailing a person's normal activity level. As with $PM_{2.5}$ exposure, ozone exposure increases asthma attacks for people with respiratory disorders. Longer-term ozone exposure may result in damage to the lung tissue and lining from inflammation, which can produce permanent and irreversible changes in lung function. Children and adults who are active outdoors are particularly susceptible to ozone, as are people with asthma and respiratory diseases. Ozone also affects sensitive ecosystems and vegetation, resulting in reduced crop yields, reduced growth and lowered pest resistance, and a lowered ability for plants and trees to survive. Additional information on the health effects to humans and vegetation from exposure to ozone is found on U.S. EPA's website: http://www.epa.gov/ttn/naaqs/standards/ozone/s_o3__index.html

U.S. EPA has long recognized the relationship between emissions of NOx and adverse regional air quality issues and federal efforts to reduce emissions of NOx were initiated in 1990. The CAA placed several new requirements to reduce NOx emissions. The federal programs that affect NOx emissions sources are discussed in the following subsections.

2.2 NOx SIP Call

Section 110 of the CAA mandates that the State of Illinois adopt a SIP containing adequate provisions to assure attainment of the primary and secondary NAAQS within its boundaries. Further, Section 110(a)(2)(D) of the CAA prohibits stationary sources from emitting air pollutants that prevent any other state from attaining the NAAQS. On October 27, 1998, U.S. EPA determined that sources in twenty-two states, including Illinois, emitted NOx in amounts that significantly contributed to nonattainment of the 1-hour ozone NAAQS in one or more downwind states, and issued a call for revisions to states' implementation plans. U.S. EPA's rule required the identified states to revise their SIP's to reduce emissions of NOx from certain sources by September 30, 1999. This action is commonly referred to as the NOx SIP Call.

To calculate the NOx budget for stationary sources for each of the NOx SIP Call states, U.S. EPA selected large electric generating units (EGU) and certain large non-EGU sources for which highly cost-effective control measures were available to reduce NOx emissions. For Illinois, U.S. EPA required an overall reduction of approximately 27 percent from its projected 2007 base ozone season total of 368,933 tons of NOx emissions.

For large RICE, U.S. EPA determined that NOx emissions should be reduced by 90 percent, a level that U.S. EPA determined to be highly cost effective. Legal challenges to the NOx SIP Call delayed implementation of the provisions affecting large RICE. On March 3, 2000, the DC Circuit issued its decision in *Michigan v. EPA* (213 *F3d* 663 (DC Cir. 2000) 69 *Fed. Reg.* 21603),[5] that U.S. EPA failed to provide adequate notice of the change in the control level assumed for large RICE. On April 21, 2004, in response to the court's decision, U.S. EPA issued a final rule[5] that required large RICE that emit one ton or more of NOx per summer day to control NOx emissions by 82 percent to 90 percent (82 percent for gas-fired and 90 percent for other liquid-fired engines). The required control level for large non-EGU turbines was 60 percent below their projected 2007 uncontrolled level. In Illinois, the NOx SIP Call affects large engines, greater than 1,500 bhp, and large turbines, 25 MW capacities and greater. This proposal is intended to satisfy this Federal requirement.

2.3 Reasonably Available Control Technology (RACT)

Pursuant to Sections 172, 182(b) and (f) of the CAA, RACT is required for all existing major sources of the applicable criteria pollutant and its precursors located in NAAs. This rulemaking addresses NO_x as a precursor to ozone and $PM_{2.5}$. U.S. 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 feasibility and economic reasonableness (70 *Fed. Reg.* 71612).[28] The major source threshold for moderate NAAs is defined as 100 TPY. A source generally consists of several units that emit pollutants. The sum of emissions from all units at the source determines if a unit is major and thus subject to RACT requirements. This rulemaking addresses two RACT categories, engines and turbines. Additional RACT categories will be addressed in subsequent rulemakings.

RACT is not a new requirement under the CAA, but one that had previously been waived with respect to Illinois' two ozone NAAs. For the implementation of the 1-hour ozone NAAQS, Illinois requested and received a waiver under Section 182(f) of the CAA from the requirement to implement NOx RACT for major sources located in ozone NAAs. With respect to the 8-hour ozone NAAQS, Illinois will not pursue the NOx waiver because the local-scale, NOx disbenefit (i.e., the scavenging of ambient ozone by local nitrogen oxide emissions) is not as important for the longer 8-hour averaging time. Also, the level of the 8-hour ozone standard is closer to regional background levels in the Midwest, which argues for the application of controls on a regional basis. Illinois therefore intends to submit a SIP revision to implement NOx RACT requirements per Sections 182(b)(2) and 182(f) of the CAA. Pursuant to 40 CFR 51.912, the State is required to submit a RACT SIP no later than 27 months (September 2006) after designation of NAAs that provides for implementation of the measures no later than the first ozone season that occurs 30 months after the RACT SIP is due (2009 ozone season). (70 *FR* 71611, 71701)[28]

This rulemaking also addresses NOx as a precursor to $PM_{2.5}$. As Section 172 of the CAA does not set a source size threshold and U.S. EPA has not finalized its proposed guidance for implementation of the $PM_{2.5}$ NAAQS, there is no lower limit of the size of the source that this requirement may affect. However, U.S. EPA has indicated in its proposed guidance that the source threshold for this requirement will not be higher than 100 TPY for NOx and SO_2 (U.S. EPA proposed a lower threshold for PM2.5). Despite the lack of guidance, states nonetheless are required to submit SIPs addressing RACT within three years of an area being designated as nonattainment, April 5, 2008.

2.4 Reasonable Further Progress (RFP)

For an area classified as an ozone NAA under Subpart 2 of Part D of the CAA, and the requirements of Section 182, a state is required to submit a SIP revision that includes measures that ensure RFP towards the emissions reductions targets needed for attainment (40 CFR 51.910). To meet RFP requirements of Section 172(c)(2) of CAA, the state is required to submit no later than 3 years (June 2007) following designation for the 8-hour NAAQS, a SIP providing for RFP from the baseline year (2002) within 6 years after the baseline year (2008). The state may use either NOx for VOM emission reductions (or both) to achieve the RFP reduction requirement. Use of NOx emissions reductions must meet the criteria in Section 182(c) (2) (C) of the CAA. For each subsequent 3-year period out to the attainment date, the RFP SIP must provide for an additional increment of progress. The increment for each 3-year period must be a portion of the remaining emission reductions needed for attainment beyond those reductions achieved for the first increment of progress (e.g., beyond 2008).

U.S. EPA has not finalized its proposed guidance for implementation of the $PM_{2.5}$ NAAQS. Preliminary guidance published on November 1, 2005, indicates that states are required to submit SIPs addressing RFP within three years of an area being designated as nonattainment.

2.5 Air Quality Impacts of Existing Regulations

Areas classified as moderate or higher for 8-hour ozone are subject to the attainment demonstration requirement for that classification under Section 182 of the CAA (40 CFR 51.910). The demonstration is due no later than 3 years after its designation. The demonstration must meet the requirements of 40 CFR 51.112 and be determined by a photochemical grid model or other method approved by U.S. EPA. Although U.S. EPA has not finalized its proposed guidance for implementation of the $PM_{2.5}$ NAAQS, preliminary guidance published on November 1, 2005, indicates that states are required to submit SIPs addressing the attainment demonstration within three years of an area being designated as nonattainment. (70 *FR* 65984).[29]

The Illinois EPA has been working with its counterparts in nearby states to develop attainment demonstrations for ozone and $PM_{2.5}$ for both of its NAAs. In the Lake Michigan region, the modeling demonstrations are being performed under the direction of LADCO. For the St. Louis metropolitan area, including Metro-East, the Illinois EPA is working closely with the Missouri Department of Natural Resources to perform the requisite modeling. The 8-hour ozone attainment demonstrations must be submitted to the U.S. EPA by June 15, 2007. The $PM_{2.5}$ attainment demonstrations are due by April 5, 2008. Although this work is ongoing, and the attainment targets for emissions reductions have not been fully identified, sufficient modeling has been conducted to date by the U.S. EPA, LADCO, and the Illinois EPA to justify the Illinois EPA's proposals to reduce NOx emissions from RICE, turbines, and other NOx emission sources statewide as part of its overall plan to attain both the ozone and $PM_{2.5}$ NAAQS in Illinois.

U.S. EPA performed air quality modeling to evaluate the air quality benefits of emission controls required by the Clean Air Interstate Rule (CAIR). U.S. EPA finalized CAIR on May 12, 2005, and CAIR is intended to address, in part, ozone and $PM_{2.5}$ air quality problems and improve public health and the environment.[30] Through air quality modeling, U.S. EPA determined that

NOx and SO_2 emissions from sources in 28 states (including Illinois) and the District of Columbia contribute significantly to nonattainment of the NAAQS for $PM_{2.5}$ and/or 8-hour ozone in one or more downwind states. U.S. EPA used the Comprehensive Air Quality Model with Extensions (CAMx) for the ozone analysis and the Community Model for Air Quality (CMAQ) for $PM_{2.5}$ (Technical Support Document for the Final Clean Air Interstate Rule – Air Quality Modeling, U.S. EPA, March 2005).[6]

U.S. EPA's model results for ozone demonstrate that regional NOx emission reductions are effective at improving ozone air quality. However, U.S. EPA also showed that, because CAIR does not provide significant NOx emission reductions in 2010, CAIR NOx emission controls provide few air quality benefits in 2010, beyond those provided by the NOx SIP Call. U.S. EPA concluded that the Chicago ozone NAA and other NAAs around Lake Michigan will continue to exceed the 8-hour ozone standard in 2010. In fact, U.S. EPA's modeling shows that the Chicago area will not attain the 8-hour ozone standard even with full implementation of CAIR in 2015, and significant additional emission reductions will be necessary.

Illinois has been shown to contribute significantly to ozone nonattainment in a number of counties downwind of Illinois. These counties and associated contributions from Illinois are given in Table 2-1, based on U.S. EPA's modeling.

For $PM_{2.5}$, U.S. EPA's modeling demonstrates that regional SO_2 and NOx reductions are effective at improving $PM_{2.5}$ air quality. The modeling also shows that CAIR NOx and SO_2 emission reductions provide some air quality benefits in 2010. For Illinois, however, the modeling shows that CAIR does not provide sufficient emission reductions for the St. Louis and Chicago NAAs to attain the $PM_{2.5}$ annual standard, even by 2015. Clearly, Illinois will need to pursue additional emission reductions beyond CAIR to achieve compliance with the $PM_{2.5}$ NAAQS.

Table 2-1

Illinois Contribution to Downwind Ozone Nonattainment Counties in 2010 Based on U.S. EPA's Modeling in Support of the CAIR Rulemaking

Downwind State	County	Contribution (ppb)
WI	Kenosha	57
WI	Ozaukee	43
WI	Sheboygan	36
MI	Macomb	16
OH	Geauga	15

Note: U.S. EPA's significance criteria is 2 ppb.

Illinois has been shown to contribute significantly to $PM_{2.5}$ nonattainment in 2010 in a number of counties downwind of Illinois. These counties and associated contributions from Illinois are given in Table 2-2, based on U.S. EPA's modeling.

Initial modeling performed by LADCO has confirmed U.S. EPA's modeling analysis of the air quality benefits of CAIR, and the need for states to pursue additional emission reductions to address residual nonattainment problems. LADCO used the CAMx model, the same model used by U.S. EPA, and an updated emissions inventory for their analysis of CAIR. It should be noted that this work is ongoing, and the attainment targets for emissions reductions have not yet been fully identified. LADCO has prepared a summary of recent modeling that describes the role of NOx emissions in causing ozone, $PM_{2.5}$, and regional haze problems in the Midwest. This document, entitled "Assessment of Regional NOx Emissions in the Upper Midwest" (February 15, 2007) is included as Attachment A of this report. LADCO's assessment demonstrates that NOx emissions from sources throughout Illinois, both in nonattainment areas and in attainment areas, contribute to ozone and $PM_{2.5}$ formation in Illinois and downwind states. LADCO's assessment also shows that emissions from both EGU and non-EGU point sources are significant components of Illinois' overall emission inventory, and that these sources contribute to air quality problems in the region, whether or not they are located within the boundaries of nonattainment areas.

Table 2-2

Illinois Contribution to Downwind $PM_{2.5}$ Nonattainment Counties in 2010 Based on U.S. EPA's Modeling in Support of the CAIR Rulemaking

Downwind State	County	Contribution (ug/m^3)
AL	Jefferson	0.21
IL	Cook	1.04
IL	Madison	0.80
IL	St. Clair	0.83
IN	Clark	0.39
IN	Dubois	0.58
IN	Lake	1.02
IN	Marion	0.76
IN	Vanderburgh	0.76
KY	Fayette	0.32
KY	Jefferson	0.38
MI	Wayne	0.42
OH	Butler	0.38
OH	Cuyahoga	0.32
OH	Franklin	0.40
OH	Hamilton	0.38
OH	Lawrence	0.21
OH	Mahoning	0.25
OH	Montgomery	0.44
OH	Scioto	0.25
OH	Stark	0.26
OH	Summit	0.30
PA	Allegheny	0.21
TN	Hamilton	0.20
WV	Cabell	0.21
WV	Kanawha	0.20

Note: U.S. EPA's significance criteria is 0.2 ug/m^3.

The Illinois EPA performed a sensitivity modeling analysis to determine the extent to which NOx emission reductions would result in ozone and $PM_{2.5}$ air quality improvements in Illinois and downwind states. This modeling used the 2009 base case developed by LADCO as the starting point to determine the sensitivity of predicted ozone and $PM_{2.5}$ concentrations to an assumed 30% reduction of NOx emissions within the modeling domain. The modeled 30% NOx emission reduction level is arbitrary and does not represent the reductions expected from a particular control strategy. LADCO's 2009 "base case" represents expected emissions due to implementation of control measures that are "on-the-books", plus the effects of economic and demographic growth by the year 2009. Other model inputs were developed by LADCO.

Modeling results for $PM_{2.5}$ are shown in Figure 2-3 for each of four quarters: January – March; April – June; July – September; and October – December. The results are depicted graphically as difference plots, showing the difference between the 2009 "base case" and the 30% NOx reduction scenario. The results indicate that a 30% NOx reduction, if achieved domain-wide from all NOx sources, will improve $PM_{2.5}$ concentrations regionally by 0.5 ug/m^3 to 1.8 ug/m^3. Improvements are shown for all four calendar quarters. The greatest benefits (spatially) are predicted to occur in the fourth quarter (October through December), and the smallest benefits (spatially) are predicted to occur in the first quarter (January through March). Improvements are also shown for all four quarters in Illinois, with predicted $PM_{2.5}$ reductions in the range of 0.5 ug/m^3 to about 1.5 ug/m^3.

Photochemical modeling for ozone was performed in a similar manner comparing the 2009 LADCO "base case" to the 30% NOx reduction scenario. For ozone, only the summertime period of June, July, and August were modeled. Similarly, the results are depicted as difference plots, which show the difference in 8-hour ozone concentrations between the two scenarios. Figure 2-4 shows the 8-hour ozone concentration differences for two days in the June 2002 regional ozone episode. Results are shown for two selected days from the three month period modeled. These days are considered representative of the results during periods of elevated ozone concentrations in the region. The results indicated that widespread improvements in 8-hour ozone concentrations are predicted to occur from the assumed 30% NOx emission reduction from all NOx sources in the modeling domain. Ozone improvements in Illinois range from 2.5 ppb to about 10 ppb.

Figure 2-3

Quarterly Average $PM_{2.5}$ Reductions from a 30% NOx Emission Reduction

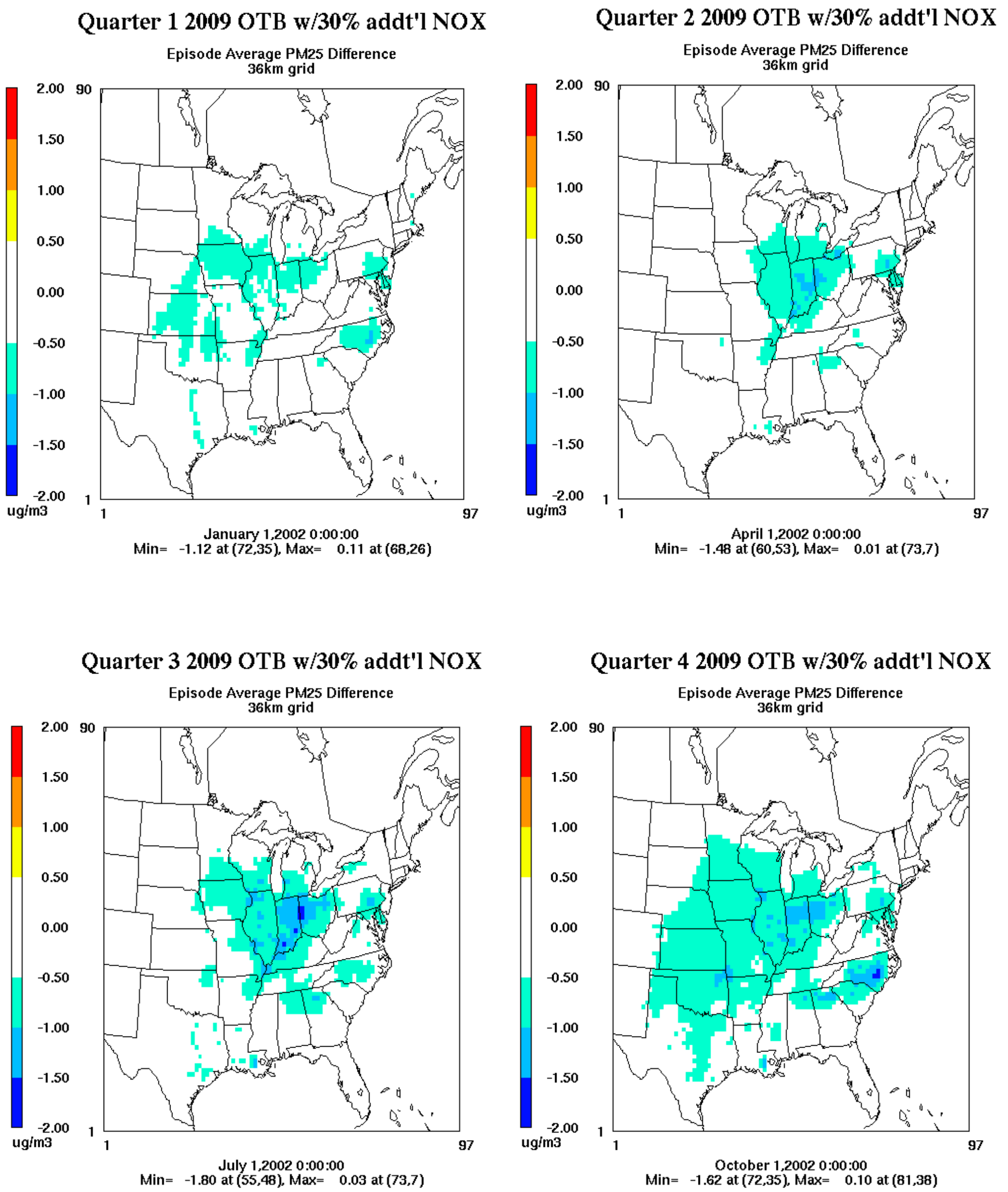
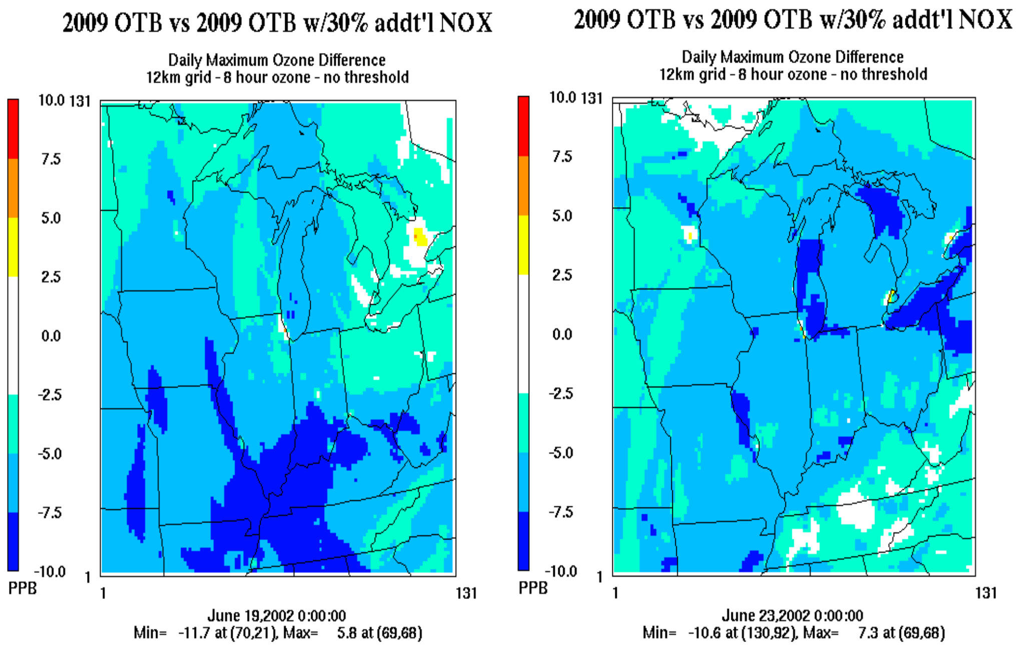


Figure 2-4

8-hour Ozone Reductions from a 30% NOx Reduction



In summary, modeling performed by U.S. EPA in support of their CAIR rulemaking suggests that CAIR does not provide for attainment with the NAAQS in Illinois. Demonstrating attainment in Illinois' NAAs will likely require additional emission reductions in Illinois beyond the reductions provided by CAIR. Air quality modeling conducted to date by the U.S. EPA, LADCO, and the Illinois EPA justifies the Illinois EPA's proposal to reduce NOx emissions from RICE, turbines, and other NOx emission sources statewide as part of its overall plan to attain the NAAQS in Illinois. Although the modeling needed to fully identify emission reduction targets for attainment are not yet completed, air quality assessments performed to date by LADCO and the Illinois EPA demonstrate that $PM_{2.5}$ and ozone air quality will improve substantially from the implementation of NOx controls from point sources in Illinois, both within and outside the nonattainment areas. As a result, Illinois is preparing a statewide NOx RACT rule, and has negotiated with electric utilities to achieve substantial NOx emission reductions which are beyond the requirements of CAIR and the Clean Air Mercury Rule (CAMR).

3.0 Process Description and Sources of Emissions

The proposed RICE/turbines rule is an essential part of Illinois' overall statewide NOx control strategy. The NOx emissions from this category accounted for approximately eight percent or 23,347 TPY of total point sources NOx emissions (277,899 TPY) for 2002 in Illinois. Reductions from this source category are an essential component of Illinois' NOx emission reduction strategy.

3.1 Stationary Reciprocating Internal Combustion Engines (RICE)

"Controlling Nitrogen Oxides Under the Clean Air Act: A Menu of Options,"[10] a document published in July 1994 by the State and Territorial Air Pollution Program Administrators (STAPPA)/Association of Local Air Pollution Control Official (ALAPCO), summarizes how RICE operate and how they generate NOx emissions. RICE are the stationary relatives of motor vehicle engines, using the combustion of fuel in cylinders to drive pistons with crankshafts, which convert the linear piston motion to rotary motion. Ignition of the fuel in reciprocating engines may be initiated by a spark or by the heat generated in the compression stroke of a piston. Spark ignited ("SI") engines typically burn gasoline or, in large engines, natural gas, while compression ignition engines burn diesel oil or a dual-fuel (diesel oil-natural gas) mixture.

Reciprocating engines have either four-stroke or two-stroke operating cycles. A typical automotive engine uses a four-stroke cycle of intake, compression, power, and exhaust. Two-stroke engines complete the power cycle in a single engine revolution compared to two revolutions for four-stroke engines.

A final classification of reciprocating engines that influence the choice of NOx control alternatives is based on the engine air-to-fuel ratio and the exhaust oxygen content. Rich-burn engines, which include four-stroke spark ignition engines, typically operate with an air-to-fuel ratio near stoichiometric and exhaust oxygen concentrations of one percent or less. Lean-burn engines, which include two-stroke spark ignition and all compression ignition engines, have a lean air-to-fuel ratio and typical exhaust oxygen concentrations of greater than one percent.

Reciprocating engines are used throughout the United States to drive compressors, pumps, electric generators and other equipment. One prominent use of large engines is to drive natural gas pipeline compressor stations. Except for three engines compressing ammonia at a chemical plant, all engines affected by the NOx SIP Call-Phase 2 rule in Illinois are used to compress natural gas at natural gas pipeline stations. All currently operating RICE that are large enough to be affected by the Illinois EPA proposal are either rich-burn or lean-burn engines that burn natural gas exclusively.

RICE are significant sources of NOx because they burn large amounts of fuel at high temperatures and pressures, which cause the nitrogen and oxygen in the air that sustains the combustion to unite and form the various oxides of nitrogen that constitute NOx. Thermal NOx is the predominant mechanism by which NOx is formed in RICE. Reducing combustion temperatures and pressures are therefore effective in reducing NOx emissions from reciprocating engines. Although in theory additional NOx could be formed from nitrogen found in the fuel, virtually all RICE burn fuels containing little if any nitrogen. Therefore, fuel NOx formation is minimal in RICE.

3.2 Stationary Turbines

The same STAPPA/ALAPCO document,[10] referenced to previously in Section 3.1 also provides a description and sources of NOx emissions from turbines. A gas turbine is an internal combustion engine that operates with rotary rather than reciprocating motion. There are three basic phases in the operation of a turbine: compression, combustion, and conversion to power. Ambient air is drawn in and compressed up to 30 times ambient pressure and directed to the combustor section where fuel is introduced, ignited, and burned. Hot combustion gases are then diluted with additional air from the compressor and directed to the turbine section at temperatures up to 2,350°F. Energy from the hot expanding exhaust gases are then recovered in the form of a shaft horsepower, of which 50 percent is needed to drive the internal compressor, and the balance of recovered shaft energy is available to drive external load units.

The heat content of gases exiting the turbine can either be discarded without heat recovery (simple cycle); used with a heat exchanger to preheat combustion air entering the combustor (regenerative cycle); used with or without supplementary firing, in a heat recovery steam generator to raise process steam temperature (cogeneration); or used with or without supplementary firing to raise steam temperature for a steam turbine Rankine cycle (combined cycle or repowering). The majority of turbines used in large stationary installations are either peaking simple cycle, two-shaft or base load, combined cycle turbines. Smaller turbines are used to compress gas in natural gas pipelines or to generate electricity.

The principle type of NOx formed in a turbine firing natural gas or distillate oil is thermal NOx. Most thermal NOx is formed in high temperature stoichiometric flame pockets downstream of fuel injectors where combustion air has mixed sufficiently with the fuel to produce the peak temperature fuel/air interface. The maximum thermal NOx production occurs at a slightly lean-fuel mixture because of excess oxygen available for reaction. The control of stoichiometry is critical in achieving reduction in thermal NOx. The thermal NOx generation also decreases rapidly as the temperature drops below the adiabatic temperature (for a given stoichiometry). Maximum reduction in thermal NOx generation can thus be achieved by control of both the combustion temperature and the stoichiometry.

Table 3-1 describes the uncontrolled NOx emissions in parts per million by volume (ppmv) corrected to 15 percent oxygen (O_2) from various types of RICE and turbines.

Table 3-1

Uncontrolled NOx Emissions from RICE and Turbines[8,10]

Type of Unit	**Uncontrolled NOx Emissions (ppmv @ 15% O_2)**	
	Range	**Average**
Rich-Burn SI Engines	880 – 1090	1060
Lean-Burn SI Engines	580 – 1360	1230
Diesel Engines	820 – 950	880
Dual-Fuel Engines	360 – 780	620
Natural Gas-fired Combustion Turbine	99 – 430	264
Distillate Oil fired Combustion Turbine	150 – 680	415

4.0 Technical Feasibility of Controls

For reciprocating engines and turbines both combustion controls and post-combustion catalytic reduction technologies can be applied to reduce NOx emissions. Combustion controls for reciprocating engines, include air/fuel ratio adjustments, low emission combustion, and prestratified charge. These controls function by modifying the combustion zone air/fuel ratio, thus influencing oxygen availability and peak flame temperature. Ignition timing retard lowers the peak flame temperature by delaying the onset of combustion. For turbines water/steam injection and dry low-NOx combustors are the combustion control technologies used to reduce NOx emissions. The two post-combustion control strategies that destroy NOx for RICE and turbines are selective catalytic reduction and non-selective catalytic reduction. U.S. EPA's Alternative Control Techniques Document--NOx Emissions from Stationary Reciprocating Internal Combustion Engines[8], and NOx Emissions from Gas Turbines,[9] provide additional details on these NOx control techniques.

4.1 Air/Fuel Ratio Adjustment

Lowering the air-to-fuel (A/F) ratio in rich-burn engines limits oxygen availability in the cylinder, thus decreasing NOx emissions both by lowering peak flame temperature and by producing a reducing atmosphere. It is generally applicable to rich-burn engines and, in addition to simple adjustment of the A/F ratio, requires the installation of a feedback controller so that changes in load and other operating conditions may be followed. Additional modification of turbocharged engines may be necessary.

Air/fuel ratio adjustment is a well-demonstrated alternative in rich-burn engines and typically yields 10-40 percent reductions in NOx emissions. This range is broad in part because a wide range of existing air/fuel ratios translates into variable scope for emissions reductions using this technique.

In lean-burn engines, increasing the A/F ratio decreases NOx emissions. Extra air dilutes the combustion gases, thus lowering peak flame temperature and reducing thermal NOx formation. In order to avoid an engine's capacity being derated, air flow to the engine must be increased at constant fuel flow, with the result that installation of a turbocharger (or modification of an existing one) is necessary to implement this technique. An automatic A/F controller also will be required for variable load operation.

Air/fuel ratio adjustment is generally applicable to lean-burn engines, although space constraints may limit the extent to which turbocharger capacity may be increased. This control method is most effective on fuel injected engines, in that carbureted engines do not have the same A/F in each cylinder, thereby limiting changes in this ratio.

Reductions in lean-burn engine NOx emissions of 5-30 percent are possible by modifying the A/F ratio. Achievable emissions reductions are limited by combustion instability and lean misfire that occur as the lean flammability limit is approached, and by decreased engine efficiency.

Air/fuel ratio adjustment is not applicable to compression ignition engines.

4.2 Ignition Timing Retard

Ignition timing retard (ITR) lowers NOx emissions by moving the ignition event to later in the power stroke when the piston has begun to move downward. Because the combustion chamber volume is not at its minimum, the peak flame temperature will be reduced, thus reducing thermal NOx formation.

ITR is applicable to all engines. It is implemented in spark ignition engines by changing the timing of the spark, and in compression ignition engines by changing the timing of the fuel injection. While timing adjustments are straightforward, replacement of the ignition system with an electronic ignition control or injecting timing system will provide better performance with varying engine load and conditions.

Emissions reductions attainable using ITR are variable, depending upon the engine design and operating conditions, and particularly on the air/fuel ratio. Reductions also are restricted by limitations on the extent to which ignition may be delayed, in that excess retard results in engine misfire. Retard also normally results in decreased fuel efficiency. For spark ignition engines, achievable emissions reductions vary from 0-40 percent, and for compression ignition engines, from 20-30 percent.

ITR results in increased exhaust temperatures, which may result in reduced exhaust valve and turbocharger life. On diesel engines, it also may result in black smoke.

4.3 Prestratified Charge

Prestratified charge (PSC) is a technology for injecting fuel and air into the intake manifold in distinct "slugs", which become separate fuel and air layers upon intake into the cylinders. This control alternative thus creates a fuel-rich, easily ignitable mixture around the spark plug and an overall fuel-lean mixture in the piston. Combustion occurs at a lower temperature, thereby producing much less thermal NOx, but without misfire even as the low flammability limit is approached.

PSC is applicable to carbureted, spark ignition four-stroke engines. Engines, which are fuel-injected or blower-scavenged, cannot use this technique. Kits for retrofitting prestratified charge are available for most engines and require installation of new intake manifolds, air hoses and filters, control valves, and a control system. Controlled emissions normally are less than 2 g/bhp-hr (140 ppm) on natural-gas-fueled engines, corresponding to emissions reductions of 80-95 percent.

4.4 Low Emission Combustion

Low emission combustion (LEC) is the combustion of a very fuel-lean mixture. Under these conditions, NOx emissions, as well as carbon monoxide (CO) and hydrocarbons (HC), are severely reduced.

Implementation of LEC requires considerable engine modification. Rich-burn engines must be entirely rebuilt, with addition or replacement of the turbocharger and installation of new air intake and filtration, carburetor and exhaust systems. The difficulty of burning very lean mixtures results in the need to modify the combustion chamber, which implies replacing pistons, cylinder heads, the ignition system and the intake manifold. While small cylinder designs that promote air-fuel mixing are available, precombustion chambers must be installed on larger engines. The chambers have 5-10 percent of the cylinder volume and allow ignition of a fuel-rich mixture that ignites the lean mixture in the cylinder.

The applicability of LEC is somewhat limited. Conversion kits are not available for all engines and refitted engines may have degraded load-following capabilities. Achievable controlled emissions are 1-2 g/bhp-hr (70-140 ppm) for rich-burn engines, which corresponds to an emissions reduction of 70-90 percent, and 1.5-3 g/bhp-hr (105-210 ppm) for lean-burn spark ignition engines, or an emissions reduction of about 80-93 percent.

LEC is not effective for diesel engines, but does work for dual-fuel engines, allowing a reduction in the fraction of diesel oil pilot fuel to 1 percent of the total, and limiting emissions to 1-2 g/bhp-hr (70-140 ppm), a decrease in emissions of 60-80 percent. Some reductions in exhaust opacity have been claimed when LEC is implemented on dual-fuel engines.

4.5 Water/Steam Injection

Water/steam injection lowers peak flame temperatures by providing an inert diluent, thus limiting thermal NOx formation. Water may be injected directly into the turbine combustor, or may be converted to steam using turbine exhaust waste heat (with a heat recovery steam generator), and then injected into the combustor.

More steam than water must be used to achieve a comparable NOx reduction. However, the use of steam results in a lower energy penalty than the use of water and may even provide NOx reductions with no energy penalty if the waste heat used to generate steam would otherwise not be recovered.

Wet injection is applicable to most, if not all, turbines, and has been applied to a large number of turbines in the United States. Required equipment, in addition to water/steam injection nozzles, includes a water treatment system, pumps or a steam generator, metering valves, and controls and piping. Untreated water will lead to deposits on turbine blades, lowering efficiency and perhaps damaging the turbine. Most turbine manufacturers sell water and steam injection systems.

Controlled NOx emissions are a function of the amount of water injected and of the fuel/nitrogen content as wet injection limits only thermal NOx formation. For natural gas, controlled emissions levels of 25-75 ppm are attained with water-to-fuel ratios of about 0.5 – 1.5 lb steam /lb fuel. (Approximately 1-2 lb steam/lb fuel is needed for equivalent control, given the lower heat capacity of steam relative to that of water.) For distillate oil, controlled emissions of 42-110 ppm are attained with similar water-to-fuel ratios. These controlled emissions levels correspond to 60-90 percent emissions reductions.

The need to increase water-to-fuel ratios for increased emission reductions limits NOx control capabilities. High water-to-fuel ratios result in increased hydrocarbon and greatly increased CO emissions. Further, because heating injected water consumes energy, turbine fuel efficiency may decrease. Wet injection may increase required turbine maintenance as a result of pressure oscillations or erosion caused by contaminates in the feed water.

Finally, the water treatment plant creates wastewater. This wastewater is enriched approximately three-fold by the dissolved minerals and pollutants that were in the raw water.

4.6 Dry Low-NOx Combustors

Dry low-NOx combustors encompass several different technologies. Lean premixed combustion is the commercially available technology that affords the largest NOx reductions. It functions by providing a large amount of excess air to the combustion chamber, lowering peak temperatures by dilution. Air and fuel are premixed in lean premixed combustors to avoid the creation of local fuel-rich, and therefore high-temperature, regions.

While retrofit low-NOx combustors are not available for all turbine models, they have been installed on many turbines in the U.S. Lean premixed combustor retrofits face varying difficulties. Because lean premixed combustors reduce thermal NOx generation only, they are less effective on oil-fired than on gas-fired turbines. Except in the case of silo combustors, which are external to the turbine body, the retrofits may require some modification of the combustor section of the turbine. Water/steam injection provides comparable reductions on oil-fired turbines without retrofit of low-NOx combustors.

Controlled emissions levels achievable on gas-fired turbines are on the order of 25-42 ppm. On some larger turbines, manufacturers are guaranteeing emissions of 9 ppm, and more will approach this limit with improvements in technology. These figures correspond to NOx emissions reductions of 60-95 percent. Maximum reductions are attained only at high turbine loads. Given reduced fuel requirements at low loads, premixing would yield air/fuel mixtures near the lean flammability limit, with resulting flame instability and high CO emissions. Thus, lean premixed combustors use diffusion flames at low loads.

4.7 Non-Selective Catalytic Reduction (NSCR)

Non-selective catalytic reduction (NSCR) uses the three-way catalysts found in automotive applications to promote the reduction of NOx to nitrogen and water. Exhaust CO and HC are simultaneously oxidized to carbon dioxide and water in this process.

NSCR is applicable only to rich-burn engines with exhaust oxygen concentrations below about 1 percent. Lean-burn engine exhaust will contain insufficient CO and HC for the reduction of the NOx present. NSCR retrofits, in addition to the catalyst and catalyst housing, require installation of an oxygen sensor and feedback controller to maintain an appropriate A/F ratio under variable load conditions. Controlled emissions achievable with NSCR are below 1 g/bhp-hr (70 ppm), corresponding to emissions reductions greater than 90 percent. NSCR controls are not feasible for turbines.[10]

4.8 Selective Catalytic Reduction

The catalyzed reduction of NOx with injected ammonia, referred to as selective catalytic reduction (SCR), has been implemented on a number of gas, diesel, and dual-fuel engines in the U.S. and abroad. SCR is applicable only to lean-burn engines with greater than about one percent exhaust oxygen, as oxygen is a reagent in the selective reduction reaction.

Retrofitting SCR involves installation of the reactor and catalyst, appropriate ductwork, an ammonia storage and distribution system, and a control system for variable load operation. Achievable emissions reductions are limited only by the amount of catalyst used, and typically are on the order of 90 percent, yielding controlled emissions below two g/bhp-hr (140 ppm). Achievable NOx emissions reductions using SCR exceed 90 percent, which corresponds to controlled emissions below 10 ppm and 25 ppm for many gas-fired and oil-fired turbines.

4.9 Technical Feasibility of Controls Summary

In summary, there are a number of techniques and control options available for reducing emissions of NOx from RICE and turbines. The degree to which these various methods reduce NOx emissions depends upon the type of engine and the fuel used in the engine. In their publication "Controlling NOx Under the Clean Air Act", [10] STAPPA/ALAPCO summarizes the potential emissions reductions from RICE and turbines. Tables 4-1 and 4-2 describe the NOx emissions reductions potential of the various control strategies for reciprocating engines and turbines.

Table 4-1
Potential Emissions Reductions from Reciprocating I. C. Engines[10]

Control	NOx Reduction Potential (%)			
	Rich-Burn Gas SI	Lean-Burn Gas SI	Diesel	Dual Fuel
Air/Fuel Ratio Adjustment	10 – 40	5 - 30	N/A	N/A
Ignition Timing Retard	0 – 40	0 - 20	20 - 30	20 – 30
Prestratified Charge	80 – 90	N/A	N/A	N/A
Low Emission Combustion	70 – 90	80 - 93	N/A	60 – 80
Non-selective Catalytic Reduction	90 – 98	N/A	N/A	N/A
Selective Catalytic Reduction	N/A	90	80 - 90	80 – 90

Table 4-2
Potential Emissions Reductions from Turbines[10]

Control	Emissions Reduction Potential (%)
Water/Steam Injection	70 - 90
Low-NOx Combustors	60 – 90
Selective Catalytic Reduction	90

5.0 Cost Effectiveness of Controls

The U.S. EPA has prepared a number of estimates of the cost effectiveness of controlling NOx emissions from RICE. The most recent and significant estimates are contained in federal ACT documents for RICE and turbines.[8, 9, 12] U.S. EPA's Regulatory Impacts Analysis (RIA) for the NOx SIP Call and responses to various states' Section 126 Petitions also contained cost estimates for controlling large RICE.[11] The Illinois EPA relied on these documents to estimate the cost effectiveness of controlling Illinois NOx sources potentially affected by this proposed rulemaking.

5.1 Cost Effectiveness of Controls on RICE

Illinois EPA relied on U.S. EPA's cost estimates from the ACT and NOx SIP Call documents for RICE.[8-12] To estimate cost effectiveness of controls, U.S. EPA considers total capital costs and total annual costs. The total capital cost is the sum of the purchased equipment costs, direct installation costs, indirect installation costs, and contingency costs. Annual costs consist of the direct operating costs of materials and labor for maintenance, operation, utilities, material replacement and disposal, and indirect operating charges including plant overhead, general administration, and capital recovery charges. Cost effectiveness, in dollars/ton of NOx removed, is calculated for each control technique by dividing the total annual cost by the annual tons of NOx removed.

U.S. EPA's ACT document describes the costs of various NOx controls applicable to reciprocating RICE. Depending on the type, size, and operating hours of the engine, the cost effectiveness of each control varies from a few hundred to several thousands dollars per ton of NOx removed. The cost information in the ACT document is reported in 1993 dollars. The Illinois EPA used Consumer Price Index (CPI) conversion factor of 0.765 for 1993 to arrive at 2004 dollars. Table 5-1 summarizes the cost effectiveness of various control options for engines equal to or greater than 500 bhp.

Based on the ACT, there are a number of control options available which achieve the control levels proposed in this rulemaking. The cost effectiveness ranges from $163 to $5,961/ton of NOx removed, based on the total annual cost divided by total annual NOx reductions.

Table 5-1

Cost Effectiveness for Retrofit of Various NOx Controls Systems[8]

Type of Control	Engine Size (bhp)	Total Capital Cost (Thousands of 2004 dollars)	Cost Effectiveness (2004 dollars/ ton of NOx removed)
Automatic A/F Control to Rich-Burn SI Engine	500 – 8000	14.9-32.0	567-1,080
Electronic Ignition to Rich-Burn SI Engine	500 – 8000	15.9-32.0	469-987
A/F + Electronic Ignition to Rich-Burn SI Engine	500 – 8000	30.8-63.9	540-1,065
Prestratified Charge to Rich-Burn SI Engine	500 – 8000	66.0-113.5	163-1,712
Prestratified Charge with Turbocharger to Rich-Burn SI Engine	500 – 8000	146.4-279.7	204-2,026
NSCR to Rich-Burn Engine SI Engine	500 – 8000	35.4-330.7	319-1,647
Low Emission Combustion to Medium Speed Rich-Burn or Lean-Burn SI Engine	500 – 8000	15.6-1,947.7	464-629
Low Emission Combustion to Low Speed Rich-Burn or Lean-Burn SI Engine	500 – 8000	639.2-4,052.3	991-2,575
Automatic A/F control to Lean-Burn SI Engine	550 - 11000	98.8-169.9	427-2,000
Electronic Ignition to Lean-Burn SI Engine	550 - 11000	15.9-32.0	652-1,556
A/F + Electronic Ignition to Lean-Burn SI Engine	550 - 11000	112.4-197.4	477-1,961
SCR to Lean-Burn SI engine	550 - 11000	457.5-1,451.0	641-3,542
Electronic Injection to Diesel Engine	500 – 8000	15.9-101.8	482-1,012
SCR to Diesel Engine	500 – 8000	308.5-1,264.1	899-4,536
Electronic Injection to Dual-Fuel Engine	700 – 8000	15.9-32.0	627-1,288
SCR to Dual-Fuel Engine	700 – 8000	333.3-1,264.1	1,165-4,745
Low-Emission Combustion to Dual-Fuel Engine	700 – 8000	941.2-5,228.8	2,928-5,961

U.S. EPA's RIAs for the NOx SIP Call and Section 126 Petitions also contain estimates of the cost effectiveness of NOx controls for large RICE under NOx SIP Call.[11] The basic approach used by U.S. EPA in estimating the potential compliance cost of the NOx SIP call to RICE was to project costs in the absence of the rule; project costs to comply with the rule; and then compare the two sets of costs. The cost to these sources in the absence of the rule is referred to as the 2007 CAA baseline or 2007 base case. Total annual compliance costs and NOx emissions changes were estimated incremental to the base case.

The geographic scope of the NOx SIP Call cost effective analyses is the 23 jurisdictions affected by the NOx SIP Call. Cost per ton of NOx removed for Illinois sources will be similar. The analyses provide results for 2007, the year in which all required emissions reduction strategies are to be fully implemented for units affected by the NOx SIP Call. All results were presented in 1990 dollars.

The potential emission reductions and control costs to RICE and other non-EGU sources affected by the NOx SIP Call were estimated using a model that is primarily based on data and assumptions from ACT documents prepared by U.S. EPA. For sources not in the trading program (e.g., RICE) the model applies control measures at individual emissions units based on a cost ceiling calculated in terms of average cost-effectiveness. The approach for sources outside the trading program provides estimates of the costs for meeting each state's emissions budget under a command-and-control scenario.

There are two types of costs incurred with the addition of NOx control technologies: a one-time capital cost for new equipment installation and annual operating and maintenance costs. In general, economies of scale exist for pollution control technologies for both capital costs and operating and maintenance costs. Thus, the size of the unit to which controls are applied and the utilization of the equipment on an annual basis will determine, in part, the cost of implementing the pollution control(s).

Table 5-2 summarizes U.S. EPA's command-and-control analyses for RICE for 5 different cost ceilings: \$1500/ton, \$2000/ton, \$3000/ton, \$4000/ton, and \$5000/ton. The analysis of large RICE was conducted by selecting the most cost-effective control measure available for each identified source that does not exceed the cost-effectiveness cut-off specified in the regulatory alternative. Table 5-2 shows the emissions reductions achieved in the analysis for each regulatory alternative. Table 5-2 indicates that the alternatives achieve incremental reductions from the 2007 controlled baseline of roughly 89 percent.

Table 5-2
2007 Ozone Season NOx Emission Reductions for Large

RICE[11]

Regulatory Alternative	Number of Affected Sources	2007 Baseline Emissions	2007 Post-Control Emissions	2007 Emission Reductions
$1,500/ton	290	92,424	9,857	82,567
$2,000/ton	304	92,424	9,840	82,584
$3,000/ton	304	92,424	9,840	82,584
$4,000/ton	304	92,424	9,840	82,584
$5,000/ton	304	92,424	9,801	82,623

Table 5-3 shows the annual costs and resulting average cost-effectiveness for each of the five assumed cost ceilings. All of the regulatory alternatives achieve similar results and all reflect control measures that meet U.S. EPA's framework for highly cost-effective ozone season NOx emission reductions. U.S. EPA selected the $5000/ton regulatory alternative as the basis for controlling RICE under the NOx SIP Call since this alternative provides the greatest emission reduction while being consistent with U.S. EPA's framework for highly cost-effective ozone season emissions reduction. This alternative results in an average reduction of 90 percent from an uncontrolled 2007 baseline.

Table 5-3
2007 Cost and Cost-Effectiveness Results for Large Stationary RICE[11]

Regulatory Alternative	Annual Control Cost (million 1990$)	Annual Monitoring and Administrative Costs (million 1990$)	Total Annual Costs (million 1990$)	Ozone Season Cost Effectiveness ($/ozone season ton)
$1,500/ton	$86.9	$12.4	$99.3	$1,203
$2,000/ton	86.9	13.3	100.2	1,213
$3,000/ton	86.9	13.3	100.2	1,213
$4,000/ton	86.9	13.3	100.2	1,213
$5,000/ton	87.1	13.3	100.4	1,215

Based on U.S. EPA's NOx SIP Call analysis, relying on the chosen regulatory alternative results in an ozone season cost effectiveness for the large RICE of $1,215 (1990 dollars) per ton of NOx reduced or $1,756 (adjusted to 2004 dollars) per ton of NOx reduced.

Another reference document that the Illinois EPA relied upon in the development of this regulatory proposal is "NOx Emissions and Control Techniques for Stationary Reciprocating Engines" (published by U.S. EPA 2000).[24] It discusses the uncontrolled and controlled levels of NOx emissions from RICE and the cost effectiveness of LEC. U.S. EPA obtained information on LEC costs from several sources. The total capital cost, annual operating cost, and cost effectiveness projections in Table 5-4 are based on actual costs for several LEC retrofits obtained from one engine manufacturer and one third party LEC vendor. Other inputs include uncontrolled NOx emissions of 16.8 g/bhp-hr, controlled emissions of 2.0 g/bhp-hr, and capacity utilization of 7,000 operating hours per year (prorated for the five months of the ozone season). In most respects, the analysis was conducted according to the methodology of the 1993 ACT document. The cost data was reported in 1990 dollars, Illinois EPA adjusted the cost data to 2004 dollars based on the CPI.

Table 5-4

Costs and Cost Effectiveness of LEC Controls in 2004 Dollars[24]

Engine Size, (bhp)	Total Capital	Annual Cost	NOx Reduction (tons)		Cost Effectiveness ($/ton NOx)	
			Annual	O_3 Season	Annual	O_3 Season
80	$231,000	$59,100	9	4	7,730	18,510
240	242,000	61,400	27	11	2,680	6,430
500	259,000	65,200	57	24	1,360	3,270
1,000	293,000	72,400	114	48	750	1,820
2,000	359,000	86,900	228	95	450	1,090
4,000	493,000	116,000	457	190	300	730
6,000	627,000	146,000	685	285	250	610
8,000	760,000	175,000	914	381	230	550

U.S. EPA's AirControlNET4.0 model is another reference that Illinois EPA relied to provide cost data for NOx controls for Illinois RICE. The AirControlNET model, Version 4.0, is a control strategy and costing analysis tool prepared by E.H. Pechan & Associates, Inc for U.S. EPA, Office of Air Quality Planning and Standards, RTP, NC. AirControlNET model was used to identify the costs of NOx controls for non-utility oil and gas combustion sources in Illinois.

Table 5-5 shows the AirControlNET costs in 2004 dollars of various NOx combustion controls available for RICE.

Table 5-5
AirControlNET Costs of Various NOx Combustion Controls Available for Illinois RICE

Unit Type	Control Type	Cost (2004$ /ton)
Rich Burn RICE-Gas, Diesel,	NSCR	496
Lean Burn RICE-Gas	LEC (Medium Speed)	724
Lean Burn RICE-Gas	LEC (Low Speed)	2,436
RICE-Gas, Diesel,	IR	1,116
RICE-Gas	AF + IR	2,276

5.2 Cost Effectiveness of Controls on Turbines

Illinois EPA relied on cost data contained in U.S. EPA's ACT[9] and AirControlNET for determining cost effectiveness estimates for control of turbines. A compilation of control costs complied by STAPPA/ALAPCO[10] is also summarized here. U.S. EPA's ACT document reference describes in detail the capital cost and cost effectiveness of various controls for turbines based on 1990 dollars. The 1990 dollar estimates have been adjusted to 2004 dollars throughout this discussion as described in Section 5.1. The cost effectiveness of two types of controls for smaller turbines of 3.3 MW varies from $2645 per ton of NOx on an annual basis removed for steam injection to $3,005 per ton of NOx removed for water injection control. For dry low-NOx combustion, cost effectiveness was $1,532 per ton of NOx removed for a four MW gas-fired turbine.

STAPPA/ALAPCO prepared a document which summarizes the cost of controlling various sizes of turbines based on the cost information contained in the ACT for the turbines. The cost information in the STAPPA/ALAPCO document[10] is reported in 1993 dollars. Table 5-6 shows the cost effectiveness of controlling 5 to 25 MW turbines operating 8,000 hours annually.

Table 5-6
Cost Effectiveness for Various NOx Controls Systems for Turbines[10]

Type of Control	Turbine Size (MW)	Total Capital Cost (thousands of 2004 dollars)	Cost Effectiveness (2004 dollars/ ton of NOx removed)
Water Injection for Gas-Fired	5 – 25	711-1,490	902-2,327
Water Injection for Oil-Fired	5 – 25	745-1,582	732-1,699
Steam Injection for Gas-Fired	5 – 25	928-2,105	993-2,614
Steam Injection for Oil-Fired	5 – 25	974-2,261	680-1,699
Low-NOx Combustor for Gas-Fired	5 – 25	630-1,438	314-1,046
SCR for Gas-Fired	5 – 25	748-2,013	1,606-3,203
SCR for Oil-Fired	5 – 25	748-2,018	1,072-2,039

U.S. EPA's AirControlNET4.0 model was also used to provide cost data for NOx controls for turbines. Table 5-7 shows the AirControlNET costs of various NOx combustion controls available for Illinois RICE and turbines.

Table 5-7
AirControlNET Costs of Various NOx Combustion Controls Available for Turbines

Unit Type	Control Type	Cost (2004$ /ton)
Turbines- N.Gas	Dry Low-NOx	712
Turbines- N.Gas	Steam Injection	1,508
Turbines- N.Gas	Water Injection	2,189
Turbines- Oil	Water Injection	1,870

In summary, the Illinois EPA believes that retrofit costs of controlling sources at proposed levels will be \$496 to \$2,436 per ton of NOx reduced for RICE and \$712 to \$2,189 per ton of NOx reduced for turbines in 2004 dollars. It should be recognized that reducing NOx emissions by combustion controls on RICE and turbines may increase carbon monoxide emissions in some cases. Illinois EPA believes that the increases in CO emissions are not significant from an air quality perspective, but may be high enough to trigger Prevention of Significant Deterioration (PSD) permitting requirements in some cases.

6.0 Existing and Proposed Regulations

6.1 Existing Illinois Regulations

In Part 217 of 35 Illinois Administrative Code, Illinois provides NOx limitations for certain fuel combustion emission units, such as boilers and certain process emission units which use or produce nitric acid. Because the Illinois air pollution regulations at 35 Ill. Adm. Code 211.2470 define “fuel combustion emission units” as boilers, furnaces, and other units that operate by indirect heat transfer, NOx emissions from reciprocating engines are not regulated in Illinois since they employ direct heat transfer. Also, pursuant to 35 Ill. Adm. Code 201.146, RICE of less than 1,118 kW (1,500 bhp) are currently exempt from permit requirements. Larger non-EGU turbines greater than or equal to 250 mmBtu/hr capacities are regulated under 35 Il. Adm. Code 217, Subpart U, which is the NOx SIP Call trading program for such units. Currently, there is no regulation to control NOx emissions from smaller turbines less than 250 mmBtu/hr capacities. The owner or operator of any new RICE and turbines is subject to new source review requirements and must meet any applicable New Source Performance Standards (NSPS) set by U.S. EPA.

6.2 Other States’ Regulations

Tables 6-1 and 6-2 contain summaries of the NOx control requirements in other states. Several states have promulgated rules limiting NOx emissions from RICE. According to the STAPPA/ALAPCO document[10], Connecticut, Louisiana, New Jersey, New York, Rhode Island, and Texas have established NOx limits based on the RACT requirements for NAAs. Typical NOx RACT limits are 1.5 – 3.0 g/bhp-hr (105-210 ppm) for gas-fired rich- and lean-burn engines, and 8-9 g/bhp-hr (584-660) for oil-fired lean-burn engines. In California, NOx emissions limits for RICE are based on the BART NOx limits. NOx limits in California’s Ventura Bay Area County Air Quality Management Districts (AQMD), Santa Barbara County AQMD, and South Coast AQMD are more stringent than RACT, and are set at 0.6 - 1.9 g/bhp-hr (42 - 133 ppm) for lean-burn engines, 0.4 – 0.8 g/bhp-hr (28 - 70 ppm) for rich-burn engines, and 1.1 - 8.4 g/bhp-hr (80-613 ppm) for diesel engines. The size cut-off for engines to apply controls varies from 50 bhp to 500 bhp in the states mentioned above.

Table 6-1

NOx Control Requirements for RICE in Other States

State	Engine Size Controlled (HP)	Control Level (g/hp-hr)		
		Gas-fired Rich Burn	Gas-fired Lean Burn	Compression Ignited Liquid Fired
Texas[13]	500 and greater	2 g/hp-hr (146 PPM) under all operating conditions	2 g/hp-hr (146 PPM)* at full load, 5 g/hp-hr (365 PPM) at 80-100% load for new SI or CI dual fuel engines manufactured after June 18, 1992; 5 g/hp-hr for older units at all loads, 8 g/hp-hr (584 PPM) at 80-100% load	11 g/hp-hr (803 PPM)
Indiana[14]	NOx SIP Call	NOx SIP Call	NOx SIP Call	NOx SIP Call
Connecticut[15]	≥ 3 MMBtu/hr (1175 HP)	2.5 g/hp-hr (183 PPM)	–	8 g/hp-hr (584 PPM)
Alabama[16]	NOx SIP Call	NOx SIP Call	NOx SIP Call	NOx SIP Call
New York[17]	200 HP in Severe Ozone Area and 400 HP in rest of State	2 g/hp-hr (146 PPM) through March 31, 2005 & 1.5 g/hp-hr (110 PPM) after April 1, 2005	3 g/hp-hr (220 PPM) through March 31, 2005 & 1.5 g/hp-hr (110 PPM) after April 1, 2005	9 g/hp-hr (657 PPM) through March 31, 2005 & 2.3 g/hp-hr (168 PPM) after April 1, 2005
New Jersey[18]	≥ 500 HP	1.5 g/hp-hr (110 PPM)	2.5 g/hp-hr (182 PPM)	8 g/hp-hr (584 PPM)
Pennsylvania[19]	153 ton NOx/Season	1.5 g/hp-hr (110 PPM) for ≥2,400 HP	3 g/hp-hr (220 PPM) for ≥ 2,400 HP	2.3 g/hp-hr (168 PPM) for ≥4,400 HP
Maryland[20]	N.G. Pipeline engines > 15% capacity factor	Limits of 300 pound/hr for a facility with 5 or less engines, and 566 lb/hr for a facility with more than 5 engines		
Antelope Valley Air Quality Management District(AVAQMD)[21]	50 HP stationary and 100 HP for portable	Electric motor, 36 PPM for stationary and 80 PPM for portable		Up to 770 PPM for ≥100 HP but less than 400 HP; 535 PPM for ≥ 400HP
San Joaquin Valley Unified Air Pollution Control District (SJVUAPCD)[22]	50 HP	50 PPM or 90% red. For waste gas/field gas engine and 25 PPM or 96% red. for others	75 PPM or 85% red for two stroke gaseous fuel < 100HP engine and 65 PPM for other	65 PPM or 90% reduction
El Dorado County Air Pollution Control District (EDCAPCD)[23]	50 HP	25 PPM to 50 PPM based on compliance dates	65 PPM to 125 PPM based on compliance date	600 PPM to 700 PPM based on compliance date
IEPA Proposed	500 HP	150 PPM	210 PPM except 365 for Worthington engines	660 PPM

Note: 1) NOx SIP Call requires 82 to 90 percent control on large engines that emitted one ton of NOx in any 1995 ozone season day.[5]

2) 1 g/hp-hr = 73 PPM conversion factor was used to convert g/hp-hr to ppmv at 15 percent O_2 on a dry basis.

Table 6-2

NOx Control Requirements for Turbines in Other States

State	Turbine Size Controlled (HP)	Control Level
Texas[13]	≥ 500 HP (0.37 MW)	3 g/hp-hr (0.82 lb/MMbtu) (220 PPM)
Indiana[14]	250 MMBtu/hr (≈ 25 MW)	Budget allowances under NOx Emissions Trading Program
Connecticut[15]	Up to 100 MMBtu/hr (≈ 10 MW)	55 PPM for Gas-fired, 75 PPM for Oil-fired
	< 100 MMBtu/hr	0.9 lb/MMBtu (224 to 245 PPM)
New York[17]	≥ 10 MMBtu/hr (≈ 1 MW)	RACT, For Simple Cycle 50 PPM for gas, 100 PPM for oil; for combined cycle 42 PPM for gas and 65 PPM for oil
New Jersey[18]	≥ 30 MMBtu/hr (≈ 3 MW)	For simple cycle gas-fired 0.2 lb/MMBtu (50 PPM), for oil-fired 0.4 lb/MMBtu (109 PPM); for combined cycle gas-fired 0.15 lb/MMBtu (37 PPM), and for oil-fired 0.35 lb/MMBtu (95 PPM)
Maryland[20]	≥ Capacity factor 15%	42 PPM for gas burning and 65 PPM for oil burning
South Coast Air Quality Management District (SCAQMD)[25]	≥ 0.3 MW	9 PPM to 25 PPM depending on the size and type
IEPA Proposed	≥ 3.5 MW	42 for gas-fired and 96 PPM for oil-fired

6.3 Proposed Illinois Regulations

The Illinois EPA considered other states NOx regulations, STAPPA/ALAPCO recommendations, and U.S. EPA guidance documents in its proposal to establish reasonable levels of NOx controls for reciprocating engines and turbines in Illinois. Size thresholds for the units affected by the proposed regulation are based on their PTE for NOx on an annual basis. Illinois EPA is proposing to control NOx emissions from sources that have a PTE of 100 TPY or more of NOx aggregated from all the affected units at the source. The proposed regulation applies to RICE of 500 bhp capacities and above, and to stationary turbines of capacities equal to or greater than 3.5 MW. The proposed regulation does not apply to emergency standby engines; engines used in research and testing for the purposes of performance verification and testing of engines; engines/turbines regulated under 35 Ill. Adm. Code 217, Subpart W; engines/turbines used for agricultural purpose; and certain portable engines. Sources can avoid the proposed control requirement by staying below source-wide NOx emissions of 100 tpy from all affected units or if the total operating rate for all affected engines is less than eight million bhp per year and all affected turbines is less than 20 thousand MW-hr per year.

Illinois EPA relied upon the U.S. EPA's ACT, TSDs for the NOx SIP Call, and STAPPA/ALAPCO guidance documents[8-12] to propose levels of controls for various types of units. All of the proposed controls levels are based on the retrofit techniques available for each category of affected unit. From review of the TSDs[12, 22] and the comments received from the affected sources during outreach, Illinois EPA determined that LEC controls on Worthington engines can achieve NOx emissions of 308-420 ppmv as compared to other spark-ignited lean burn engine that can achieve NOx emissions below 210 ppmv. Therefore, an average limit of 365 ppmv is proposed for Worthington engines. Although, post-combustion controls, such as SCR, are available and can achieve the greatest reductions, the proposed control levels do not require SCR as a compliance method.

Section 182(f) of the CAA introduced the requirement for existing major stationary sources of NOx in NAAs to install and operate RACT to control NOx emissions. The statewide NOx control levels proposed in this submittal are considered reasonable, attainable, and cost-effective. The NOx emissions levels are prescribed in ppmv corrected to 15 percent O_2 on a dry basis. The NOx limits for engines are 150 ppmv for spark-ignited rich-burn, 210 ppmv for spark-ignited lean-burn, 365 ppmv for Worthington engines and 660 ppmv for diesel engines and for turbines the NOx limits are 42 ppmv for gas-fired and 96 ppmv for liquid-fired. An owner or operator may comply with the control requirements by averaging the emissions of affected units that commenced operation on or before January 1, 2002, unless the unit is a replacement unit, in which case such a unit may be included even if it commenced operation after January 1, 2002. Compliance with the emission limits will be determined on both an ozone season (May 1, to September 30) and an annual (January 1 to December 31) basis each year. For units included in an averaging plan, and units using Continuous Emissions Monitoring Systems (CEMS), compliance with the emission limits must be demonstrated each year. For all other unites, compliance will be demonstrated on a periodic basis using stack tests and portable monitoring systems.

Illinois EPA reviewed the U.S. EPA's TSDs[12, 22] and determined that most engines and turbines can reasonably achieve the proposed NOx emission limitations. However, some engines or turbines may have difficulty in achieving the proposed limits. Therefore, Illinois is also proposing a NOx emissions averaging option to assist sources in complying with the regulations. To take advantage of this flexible approach, a company must submit an averaging plan which lists all of its units that will be included under this option. The total sum of the *actual* NOx emissions from each engine or turbine in an averaging plan (based on stack tests results and annually monitored data) must be less than the total sum of the *allowable* NOx emissions from those engine and turbines in the averaging plan based on the respective control level proposed. If sources, which are using an averaging plan, replace their fuel combusting units with electric motors, the allowable NOx emissions from the affected units that were replaced should be used in the averaging calculations and the actual NOx emissions for the electric motors are considered zero. The allowable NOx emissions from the electric motor is determined by multiplying the total bhp-hrs generated by the motor (bhp rate of motor x operating hours) by the allowable NOx emission rate of the replaced unit in lbs/mmBtu and converting the pounds of NOx emissions using the factor of 0.00077 mmBtu/bhp-hr. The conversion factor was derived by using a standard conversion factor of one bhp-hr equals to 2545.1 Btu and engine thermal efficiency of 33%.

For a replacement unit which is not electric, the allowable NOx emission rate to be used in the averaging plan prior to its compliance date will be the higher of the applicable uncontrolled NOx emission rate from the U.S. EPA's AP-42 document or the actual NOx emission rate as determined by testing or monitoring. On and after the applicable compliance date for the replacement unit, the allowable NOx emission rate will be the allowable applicable NOx emission concentration limit specified in the proposed rule.

For a unit that is replaced with purchased power, the allowable NOx emission rate will be the applicable NOx emissions concentration specified in the proposed rule. The actual hours of operation to be used will be the annual hours of operation for the replaced unit averaged over the three-year period prior to the date of purchasing power. Purchased power units may be included in an emission averaging plan for no more than five years.

Tables 6-3 and 6-4 provide examples of how the proposed averaging plan will work. Table 6-3 shows an example plan which includes four engines and one turbine. In this example, actual NOx emissions of 812,965 pounds are greater than the allowable NOx emissions of 804,666 pounds; therefore, the source is not in compliance with the proposed rule. Table 6-4 shows that by adjusting the operating hours of each engine and turbine, the actual NOx emissions of 783,316 pounds, therefore the company achieves compliance without any penalty in fuel consumption and total bhp-hrs in a year.

Table 6-3
Example of Averaging Plan-Case 1

Engines	Rated bhp	Allow. NOx Limit (PPM)	Actual NOx Limit (PPM)	Fuel Use (mmBtu/yr)	Hours of Oper.	Bhp-hrs x10^3	Allow. NOx (lb)	Actual NOx (lb)
Engine 1	3,000	150	175	127,500	5,000	15,000	70,456	82,199
Engine 2	3,500	210	220	148,750	5,000	17,500	115,078	120,558
Engine 3	4,000	660	700	170,000	5,000	20,000	436,121	462,553
Engine 4	4,500	210	150	191,250	5,000	22,500	147,958	105,684
Turbine 5	5,361	42	50	227,843	5,000	26,805	35,253	41,968
Total				865,343	25,000	101,805	804,866	812,962

Table 6-4
Example of Averaging Plan-Case 2

Engines	Rated bhp	Allow. NOx Limit (PPM)	Actual NOx Limit (PPM)	Fuel Use (mmBtu/yr)	Hours of Oper.	Bhp-hrs x10^3	Allow. NOx (lb)	Actual NOx (lb)
Engine 1	3,000	150	175	114,750	4,500	15,000	63,410	73,979
Engine 2	3,500	210	220	133,875	4,500	17,500	103,570	108,502
Engine 3	4,000	660	700	156,400	4,600	20,000	401,231	425,548
Engine 4	4,500	210	150	232,475	6,078	22,500	179,851	128,465
Turbine 5	5,361	42	50	227,843	5,000	26,805	35,253	41,968
Total				865,343	24,678	101,805	783,316	778,463

Owners or operators of reciprocating engines impacted by the NOx SIP Call are required to comply with the proposed rule on or before May 1, 2007. An owner or operator of any affected engine not subject to the NOx SIP Call, and affected turbines located in Cook, DuPage, Grundy, Kane, Kendall, Lake, McHenry, Will, Jersey, Madison, Monroe, Randolph, or St. Clair counties (NAA counties) are required to comply with the rule by January 1, 2009. All affected engines rated at 1,500 bhp or more and turbines rated at 5 MW (6,702 bhp) or more that are neither subject to the NOx SIP Call nor located in the NAA counties are required to comply with the rule on and after January 1, 2011. All other affected engines rated at ≥ 500 bhp but less than 1,500 bhp and turbines rated ≥ 3.5 MW but less than 5 MW that are neither subject to the NOx SIP Call nor located in the above mentioned NAA Counties are required to comply with the rule on and after January 1, 2012. Table 6-5 summarizes the compliance schedule dates for various types of affected units.

The January 1, 2009 compliance date of the proposed rule was chosen to obtain the greatest amount of NOx emissions in NAAs in Illinois EPA's efforts to reach attainment by U.S. EPA's prescribed attainment dates of June 2010 for the new ozone and $PM_{2.5}$ NAAQS. [28, 29] (70 FR-71612) (70 FR 65984)

The January 1, 2011 compliance date of the proposed rule was chosen to further assist in minimizing transport of NOx emissions into NAAs and thereby improve air quality. Modeling by U.S. EPA and LADCO indicates that additional reductions will be necessary to reach attainment for the ozone and $PM_{2.5}$ NAAQS. In addition, outreach discussions with impacted sources indicates that obtaining control equipment and technical support for installation could create long delivery time and delays with increased market demands. These less impacting NOx sources were given additional compliance times to alleviate the potential equipment backlog for the larger and more local NOx sources.

Similarly, the January 1, 2012 date was chosen to also allow these smaller NOx sources more time to comply and alleviate some of the market demand for control equipment and technical staff for larger and local NOx sources.

Table 6-5
Compliance Schedule for Affected Units

Affected Units	Compliance Date
NOx SIP Call Units	May 1, 2007
RICE and Turbines Located in NAA Counties	January 1, 2009
RICE ≥ 1,500 bhp and Turbines ≥ 5 MW located in Attainment Counties	January 1, 2011
All Other RICE ≥ 500 bhp but < 1,500 bhp and Turbines ≥ 3.5 MW but < 5 MW located in Attainment Counties	January 1, 2012

The proposed regulations provides for the limited use of CAIR NOx allowances to comply with the emission limitations. The use of CAIR NOx allowances are limited to documented unforeseen or anomalous operating scenarios inconsistent with historical operations for a particular ozone season or calendar year. This compliance option can not be used more than twice in any five-year rolling period and also can not be used by the affected NOx SIP Call units. The owner or operator shall surrender one NOx allowance for each ton or portion of a ton of NOx emissions on an annual basis by which actual emissions exceed allowed emissions.

An owner or operator of an engine or a turbine subject to the proposed control limits shall perform a compliance performance test once every five years to demonstrate compliance with the rule. For engines subject to the NOx SIP Call, the initial compliance test must be performed by May 1, 2007. For all other affected units, an initial compliance test must be performed by the later of the applicable compliance date or within the first 876 hours of operation. In addition, all affected units must be tested once every five years thereafter. Section 217.394 of the proposal provides methods and procedures for testing and monitoring of the performance of an affected unit. The test methods provided are approved by the U.S. EPA as set forth in 40 CFR 60.

Pursuant to proposed Section 217.396, an owner or operator of an affected unit is required to maintain the required records such as, but not limited to:

- Records to identify impacted engines, calendar date of records;
- Type and quantity of fuel used on a monthly basis,

- Results of monitoring performed on the affected unit and reported deviations, a log of inspection and maintenance performed;
- Copies of the calculations used to demonstrate compliance with ozone season and annual control period limits;
- Number of operating hours, periods of malfunction and repairs; and
- Corrective action taken to meet limits or control levels for a period of five years at the source at which the affected unit is located.

Proposed Section 217.396 also provides reporting requirements such as, but not limited to:

- Notifying the Illinois EPA 30 days and five days prior to testing;
- Submitting results of tests to the Illinois EPA within 30 days;
- Reporting any monitored exceedances of the applicable NOx concentration;
- Amending the applicable permit within 90 days of shutting down the unit;
- Notifying the Illinois EPA by October 31 if the averaging plan cannot demonstrate compliance for any ozone season;
- Reporting annually by January 30 the total mass of allowable and actual NOx emissions for the ozone season and annual control period from all affected units in the averaging plan;
- Providing annually by January 30 the information required to determine actual NOx emissions; and
- Providing annually by January 30 the calculations that demonstrate the total actual NOx emissions are less than the total allowable NOx emissions.

7.0 Potentially Affected Sources

7.1 Sources Affected by the NOx SIP Call

To determine the impacted sources resulting from the NOx SIP Call, the Illinois EPA used the U.S. EPA's corrected 1995 base year inventory (March 2, 2000) that contained the NOx emissions sources for each of the affected states. A computer search of the corrected 1995 NOx inventory revealed that there were 28 internal combustion reciprocating engines located in Illinois that emitted more than one ton of NOx per day during the ozone season in 1995, which is the applicability level of the NOx SIP Call. Of these 28 impacted engines, three are located at a chemical manufacturing company and are used to compress ammonia gas, and 25 are located at natural gas pipeline facilities to run compressors. Attachment B to this TSD lists those units impacted by the NOx SIP Call and specifies the required NOx emissions reductions from each impacted unit needed to meet the requirements of the NOx SIP Call.

7.2 Other Potentially Affected Sources

To determine potentially affected engines and turbines besides those impacted by the NOx SIP Call, the Illinois EPA reviewed its 2004 inventory of RICE and turbines. Illinois EPA removed the units that were subject to 35 Ill. Adm. Code 217, Subpart W, NOx regulations for EGU. Remaining was a total of 1,200 RICE and 205 turbines in 2004 NOx inventory that have the potential to be affected by the proposed regulations.

The Illinois EPA estimates that NOx emissions from these potentially affected units in Illinois were 27,366 TPY and 13,536 tons per ozone season. The Illinois EPA estimates that of the 1,200 potentially affected RICE in Illinois, 202 RICE would be impacted by the proposed rule based on 2004 operating rates. Of the 205 potentially affected gas turbine units, 36 would be impacted when 2004 operating rates are accounted for. These estimates are conservative and are based on the assumption that sources that do not operate more than eight million bhp-hrs in a year or 20,000 MW-hrs in a year will have their permit revised to limit their operations to take advantage of exemption levels. Also, the Illinois EPA based its estimates conservatively by using the estimated normal operation of the each unit and did not base it on the PTE estimates which would increase the number of impacted sources considerable. A list of impacted sources of this proposal is included in the Attachment C to this TSD.

Current Illinois regulations do not require sources to obtain permits to operate RICE with a capacity of less than 1,500 bhp. Therefore, the Illinois NOx inventory does not include all the engines from 500 to 1,500 bhp that may be affected by this proposal. To identify potentially affected sources and to estimate NOx emissions reductions from sources, with smaller engines, the, the Illinois EPA, with the assistance of the Department of Commerce and Economic Opportunity (DCEO), conducted a statewide survey of industries and businesses and mailed 10,025 survey forms to determine how many engines in the 500 to 1,500 bhp size range are in Illinois. Out of 10,025 surveys, only 458 were returned and, of those, only 8 reported having RICE in the range of 500 to 1500 bhp. Assuming the same proportion of affected engines per number of responses applies to those that did not respond to the survey, the Illinois EPA estimates that there are approximately 175 units that have the potential to be affected by the proposed rule. The Illinois EPA further assumed that many of these units would qualify for exemptions and therefore, only approximately 44 engines would be impacted by this proposal. Table 7-1 summarizes the number of impacted sources of this proposal using this very conservative methodology.

Table 7-1

Number of Affected Sources

Unit Type	Potentially Affected	Impacted
IC Engines ≥ 1,500 bhp	1,200	202
Non-EGU Turbines ≥	205	36
IC Engines ≥ 500 bhp & < 1,500 bhp	175	44
Total	1,580	282

8.0 NOx Emissions Reductions

8.1 Reductions from Sources Affected by the NOx SIP Call

The Illinois EPA used U.S. EPA's 1995 NOx SIP Call emission inventory to determine NOx emissions from those sources impacted by the federal rulemaking. Daily NOx emissions from the impacted units were multiplied by 153 to obtain the ozone season NOx emissions. Since the NOx SIP Call NOX "budget" was based on the projected 2007 ozone season, the 1995 seasonal NOx emissions were multiplied by a NOx growth factor for each affected unit to forecast the 2007 ozone season NOx emissions. U.S. EPA relied on the economic growth projection model (EGAS) to provide the growth factors for each emission unit for Illinois sources. Total projected 2007 seasonal NOx emissions from these 28 sources were calculated to be 6,618 tons.

The Illinois EPA applied a control efficiency of 82 percent to the 2007 seasonal NOx emissions to the uncontrolled 2007 seasonal NOx emissions to obtain the 2007 seasonal which is consistent with U.S. EPA's modeling to obtain the total 2007 season NOx emissions for affected units. The required control on these engines will reduce 2007 base emissions by 5,422 tons per season, to a controlled level of 1,196 tons per season. Attachment B to this TSD identifies the 28 emission units potentially impacted by the proposed regulation and the required NOx emissions reduction to comply with NOx SIP Call Phase II requirements. Based on the average uncontrolled level NOx emission rate of 16.8 g/bhp-hr as reported in the U.S. EPA's TSD[12] and a controlled NOx emission rate of 3 g/bhp-hr (210 ppmv), the Illinois EPA's proposal meets the NOx SIP Call emissions reduction requirement for natural gas-fired RICE.

8.2 Reductions from Other Affected Sources

As described in Section 7.2, the Illinois EPA estimated that the total 2004 NOx emissions from the 202 RICE and 36 turbines potentially affected by this proposal to be 19,936 TPY and 8,491 tons per ozone season. The Illinois EPA applied an 82 percent control level to gas-fired engines, 25 percent control efficiency to diesel engines, and 60 percent control efficiency to turbines to estimate NOx emissions reductions from the proposed rule. No control was applied to a turbine which is subject to NSPS for NOx emissions. When fully implemented in 2012, the proposed rule will achieve estimated NOx emissions reductions from affected sources (including NOx SIP

Call impacted engines) of 15,199 tons per year and 6,427 tons per ozone season from RICE greater than 1,500 bhp and turbines greater than 3.5 MW as shown in Tables 8-1, 8-2 and 8-3.

Table 8-1

Estimated NOx Emissions Reductions from Affected RICE

Year	Uncontrolled NOx		NOx Emissions Reductions	
	(tons/yr)	(tons/season)	(tons/yr)	(tons/season)
2009	7,874	3,314	6,257	2,634
2011	15,725	6,707	12,415	5,278
2012	18,276	7,777	14,412	6,093
2012 Small units	3,256	1,357	2,670	1,113
2012 Total	21,532	9,134	17,082	7,206

Table 8-2

Estimated NOx Emissions Reductions from Affected Turbines

Year	Uncontrolled NOx		NOx Emissions Reductions	
	(tons/yr)	(tons/season)	(tons/yr)	(tons/season)
2009	780	337	259	108
2011	1,524	657	705	300
2012	1,660	714	787	334

Table 8-3

Estimated NOx Emissions Reductions from Affected RICE and Turbines

Year	Uncontrolled NOx		NOx Emissions Reductions	
	(tons/yr)	(tons/season)	(tons/yr)	(tons/season)
2009	8,654	3,651	6,515	2,742
2011	17,385	7,420	13,203	5,612
2012	19,936	8,491	15,199	6,427
2012 Small units	3,256	1,357	2,670	1,113
2012 Total	23,192	9,848	17,869	7,540

To estimate NOx emissions reductions from the smaller RICE, between 500 bhp and 1,500 bhp, the Illinois EPA assumed the average capacity of the impacted RICE to be 1,000 bhp and the estimated operating schedule to be 4,000 hours per year. At a NOx emission rate of 16.8 g/bhp-hr, the estimated 2004 NOx emissions were determined to be 3,256 tons NOx per year. At a control efficiency of 82 percent, the NOx reduction from these engines will be 2,670 TPY and 1,113 tons per ozone season in 2012. Table 8-1, 8-2, and 8-3 show the estimated NOx emissions reductions from "small units" with their corresponding total NOx emissions reductions.

As shown in Table 8-3, this proposal will provide NOx emissions reductions of 17,869 TPY and 7,540 tons per ozone season when fully implemented in 2012. This equates to a reduction in NOx emissions of 65 percent on an annual basis and 55 percent during the ozone season from all RICE and turbines in Illinois.

9.0 Summary

This Technical Support Document presents the rationale, the documentation, and the methodology relied on by the Illinois EPA in the development of its proposed regulation to control NOx emissions from reciprocating internal combustion engines (RICE) and turbines. NOx emissions are a contributor to fine particulate matter ($PM_{2.5}$) and ozone levels in areas of Illinois that are designated as nonattainment areas (NAAs) for these pollutants. Reciprocating internal combustion engines and turbines are a source category that accounts for eight percent or 23,347 TPY of total point source NOx emissions in Illinois. The proposed regulation is being submitted to the Illinois Pollution Control Board to satisfy the requirements of the 2004 NOx SIP Call Phase II, the CAA Section 110 requirements for NOx RACT on major sources, and as a SIP control strategy to assist Illinois in reaching attainment of the 8-hour ozone and $PM_{2.5}$ NAAQS.

U.S. EPA's final NOx SIP Call published on April 21, 2004, requires RICE that emit more than one ton per day of NOx emissions during the ozone season to reduce their NOx emissions by 82 percent for gas-fired and 90 percent for other liquid-fired engines relative to 1995 levels. The required control level for large non-EGU turbines is 60 percent below their projected 2007 uncontrolled level. This regulatory proposal, if adopted, requires Illinois RICE and turbines impacted by the NOx SIP Call to comply with the NOx reduction requirements by May 1, 2007, thereby satisfying this federal obligation.

This proposal is also intended to address the CAA requirement for NOx RACT for RICE and turbines in 8-hour ozone and $PM_{2.5}$ NAAs. Section 110 of the CAA mandates that the State of Illinois adopt a SIP containing adequate provisions to assure attainment of the primary and secondary NAAQS within its boundaries. The proposed regulation requires affected units at a source with the potential to emit (PTE) 100 tons per year (TPY) of NOx to apply control technology that is economically reasonable and technologically feasible. In addition to RICE and turbine regulations, Illinois EPA is in the process of developing statewide regulations to control other NOx source categories, as needed, to satisfy the CAA requirement for NOx RACT.

Furthermore, Section 110(a)(2)(D) of the CAA prohibits major stationary sources from emitting air pollutants that prevent any other state from attaining the NAAQS. Sufficient modeling has been conducted to date, by the U.S. EPA, LADCO, and the Illinois EPA, to justify the Illinois EPA's proposals to reduce NOx emissions from RICE, turbines, and other NOx emission sources statewide as part of its overall plan to attain the NAAQS in Illinois and to mitigate any transport of NOx emissions to downwind states.

In the submitted rule, Illinois EPA is proposing to control NOx emissions statewide from sources that have a PTE of 100 TPY or more of NOx aggregated from all the affected units at the source. The proposed regulation applies to RICE of 500 bhp capacities and above, and to stationary turbines of capacities equal to or greater than 3.5 MW. The proposed regulation does not apply to emergency standby engines; engines used in research and testing for the purposes of performance verification and testing of engines; engines/turbines regulated under 35 Ill. Adm. Code 217, Subpart W; engines/turbines used for agricultural purposes; and certain portable engines. Sources can avoid the proposed control requirement by staying below source-wide NOx emission levels of 100 TPY from all affected units or by operating all affected engines less than eight million brake-hp-hr and all affected turbines less than 20 thousand MW-hr per year.

Staggered compliance dates are proposed in the Illinois rule submittal. Owners or operators of reciprocating engines impacted by the NOx SIP Call are required to comply with the proposed rule by May 1, 2007. An owner or operator of any affected turbine or engine not subject to the NOx SIP Call and located in an ozone or $PM_{2.5}$ NAA, must comply with the rule by January 1, 2009. All affected engines rated at 1,500 bhp or more and turbines rated at 5 MW (6,702 bhp) or more that are neither subject to the NOx SIP Call nor located in the NAA counties are required to comply with the rule by January 1, 2011. All other affected engines and turbines are required to comply with the rule by January 1, 2012. From outreach discussions, this approach was recommended to help alleviate anticipated equipment and material delays, as well as demands on technical staffing needed for installation and testing of new controls, without sacrificing critical emission reductions.

Illinois EPA is also proposing a NOx emissions averaging option to assist sources in complying with the regulations. To take advantage of this flexible approach, a company must submit an averaging plan which lists all of its units that will be included under this option. The total sum of the actual NOx emissions from each engine or turbine in an averaging plan (based on stack tests results and annually monitored data) must be less than the total sum of the allowable NOx emissions from those engine and turbines in the averaging plan based on the respective control level proposed.

The proposed regulations will reduce NOx emissions by 5,422 tons per ozone season in 2007 ozone control season and satisfy the U.S. EPA's NOx SIP Call Phase II requirements for RICE. In addition, the proposed regulation will impact approximately 202 RICE (NOx SIP Call engines included) and 36 turbines in Illinois when fully implemented in 2012. When fully implemented, the proposed rule will reduce the statewide NOx emissions from RICE by approximately 17,082 TPY and 7,206 tons per ozone control season at a cost effectiveness of $496 to $2,436 per ton of NOx (in 2004 dollars). Emissions from gas turbines will be reduced by approximately 787 TPY and 334 tons per ozone season at a cost effectiveness of $712 to $2,189 per ton of NOx (in 2004 dollars). This equates to 65 percent NOx emissions reduction annually and 55 percent NOx emissions reduction in the ozone season from the RICE and turbines in Illinois. From a perspective of only affected units, the proposed rule, if adopted will result in a 77 percent NOx emissions reductions annually and seasonally.

10.0 References

1. National Ambient Air Quality Standards for Ozone, 62 *FR* 38855, July 18, 1997, (Ozone Standards).

2. National Ambient Air Quality Standards for Particulate Matter, 62 *FR* 38652, July 18, 1997, ($PM_{2.5}$ Standards).

3. The Clean Air Act (CAA), 42 U.S.C. 7401 *et seq.*

4. Finding of Significant Contribution and Rulemaking for Certain States in the Ozone Transport Assessment Group Region for Purposes of Reducing Regional Transport of Ozone; Rule. Part II, Environmental Protection Agency, 63 FR 57356, Tuesday, October 27, 1998.

5. Interstate Ozone Transport: Response to Court Decisions on the NOx SIP Call, NOx SIP Call Technical Amendments, and Section 126 Rules; Final Rule. 69 FR 21603, April 21, 2004.

6. Technical Support Document for Final Clean Air Interstate Rule, Air Quality Modeling, U.S. EPA, Research Triangle Park, NC, March 2005.

7. LADCO, Attainment Strategy Options, Draft, October 28, 2005.

8. Alternative Control Techniques Document--NOx Emissions from Stationary Reciprocating Internal Combustion Engines EPA-453/R-93-032, July 1993, U.S. EPA, OAQPS, RTP, NC 27711.

9. Alternative Control Techniques Document – NOx Emissions from Stationary Gas Turbines, EPA-453/R-93-007, January 1993, U.S. EPA, OAQPS, Research Triangle Park, NC 27711.

10. Controlling Nitrogen Oxides Under the Clean Air Act: A Menu of Options, July 1994, State and Territorial Air Pollution Program Administrators/Association of Local Air Pollution Control Officials.

11. Regulatory Impacts Analysis for the NOx SIP Call, FIP, and Section 126 Petitions, Volume 1: Costs and Economic Impacts, EPA-452/R-98-003, September 1998, U.S. EPA, Office of Air and Radiation, Washington, DC20460.

12. Stationary Reciprocating Internal Combustion Engines Technical Support Document for NOx SIP Call, October 2003, Doug Grano/Bill Neuffer, EPA, OAR, OAQPS, OPSG.

13. Texas Administrative Code. Title 30, Rule 106.512: Stationary Engines and Turbines.

14. Indiana Department of Environmental Management, Office of Air Quality, Section 9.326 IAC 10-5. Rule 5 Nitrogen Oxide Reduction Program for Internal Combustion Engines (ICE).

15. Document Prepared by the State of Connecticut, Department of Environmental Protection. Sec. 22a-174-22 Control of Nitrogen Oxides Emissions.

16. Alabama Department of Environmental Management. Air Division, Chapter 335-3-8, Nitrogen Oxides Emissions.

17. New York State, Department of Environmental Conservation Rule and Regulations, Subpart 227.2, Reasonable Available Control Technology (RACT) for Oxides of Nitrogen (NOx).

18. New Jersey State Department of Environmental Protection, New Jersey Administrative Code Title 7, Chapter 27, Subchapter 19: Control and Prohibition of Air Pollution from Oxides of Nitrogen.

19. Pennsylvania Department of Environmental Protection, Air Quality Regulations, Small Source of NOx Cement Kilns and Large Internal Combustion Engines, 25 PA Code CHS 121,129 and 145.

20. Code of Maryland Regulations. Title 26 Department of the Environment. Subtitle 11 Air Quality, Chapter 09: Control of Fuel-Burning Equipment, Stationary Internal Combustion Engines, and Certain Fuel-Burning Installation.

21. Antelope Valley Air Quality Management District. Rule 1110.2: Emissions from Stationary, Non-Road & Portable Internal Combustion Engines.

22. San Joaquin Valley Unified Air Pollution Control District Rule 4702: Internal Combustion Engines – Phase 2.

23. El Dorado County Air Pollution Control District Rule 233: Stationary Internal Combustion Engines.

24. Stationary Reciprocating Internal Combustion Engines, Updated Information on NOx Emissions and Control Techniques, Revised Final Report, EPA Contract No. 68-D-026, Work Assignment No. 2-28,EC/R Project No. ISD-228, September 1, 2000.

25. South Coast Air Quality Management District, Rule 1134 – Emissions of Oxides of Nitrogen from Stationary Gas Turbines.

26. Air Quality Designations and Classifications for fine Particles ($PM_{2.5}$) National Ambient Air Quality Standards, 70 *FR* 943, January 5, 2005.

27. 8-hour Ozone National Ambient Air Quality Standards, 69 *FR* 23858, April 30, 2004.

28. Final Rule to Implement the 8-Hour Ozone National Ambient Air Quality Standard, 70 *FR* 71612, November 29, 2005.

29. Proposed Rule to Implement the fine Particle National Ambient Air Quality Standards, 70 *FR* 65984, November 1, 2005.

30. Rule to Reduce Interstate Transport of Fine Particulate Matter and Ozone (Clean Air Interstate Rule); Revisions to Acid Rain Program; Revisions to the NOx SIP Call, 70 *FR* 25162, May 12, 2005.

Attachment A

Assessment of Regional NOx Emissions in the Upper Midwest

Prepared by the
Lake Michigan Air Directors' Consortium

February 15, 2007

Assessment of Regional NOx Emissions in the Upper Midwest

The purpose of this document is to summarize the results of air quality analyses performed by the Lake Michigan Air Directors Consortium (LADCO) for NOx emissions. NOx emissions are a precursor to ozone and $PM_{2.5}$ (particulate nitrate) concentrations. The following sections review NOx emissions for two base years (2002 and 2005) and three projected future years (2009, 2012, and 2015), and the effect of NOx emissions on ozone and $PM_{2.5}$ concentrations and regional haze levels.

NOx Emissions

NOx emissions are summarized by year and source sector for the 5-state LADCO region in Figure 1, and by state and source sector for 2009 in Figure 2.

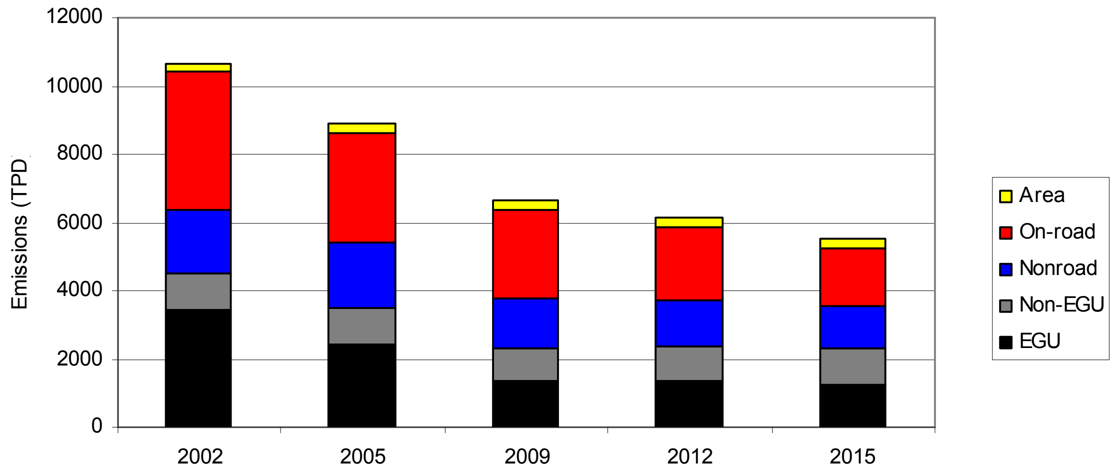


Figure 1. NOx emissions for 5-state LADCO region (tons per day)

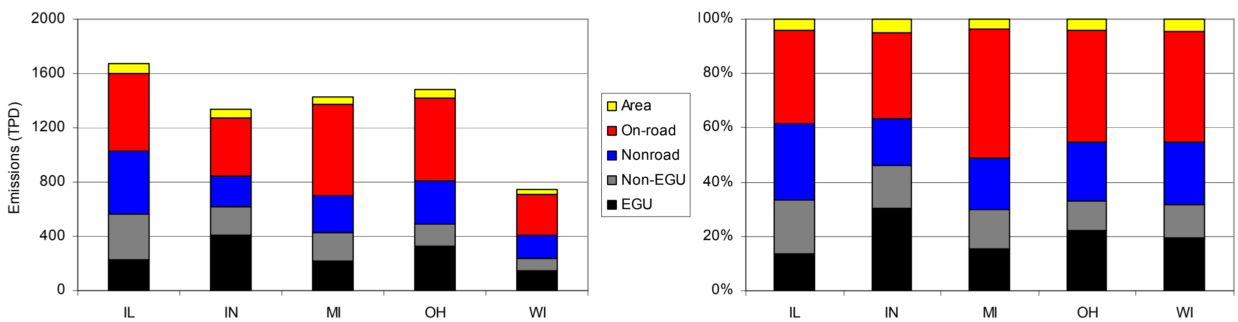


Figure 2. NOx emissions by state for 2009 – absolute amounts (left) and percentages (right)

Mobile sources (on-road and off-road) make-up the largest source sector: about 60% of the regional emissions in the base years (2002, 2005) and future years (2009, 2012, 2015). NOx emissions from on-road sources will decrease by almost 40% between 2002 and 2009 due to federal motor vehicle control programs.

Point sources (EGUs and non-EGUs) make-up the next largest source sector: about 35% of the regional emissions in the base years and future years. EGU emissions will decrease by more than 60% between 2002 and 2009 due to the NOx SIP Call and CAIR. Nevertheless, EGUs still make-up 20% of the regional emissions in the future years. Non-EGUs make-up 15% of the regional emissions in the future years. Important non-EGU source categories include ICI boilers (5% of the regional emissions), IC engines (3%), cement manufacturing (1.3%), metal production (1.3%), and petroleum refineries (1%).

Area sources make-up a small percentage of the regional NOx emissions: less than 5%.

The absolute amount of NOx emissions varies by state, although the relative percentage of each source sector is similar, except for Indiana. (Note, there is a higher percentage of point source NOx emissions in Indiana, compared to the other four LADCO States.)

Ozone

A photochemical grid model (CAMx) was applied to provide source contribution information. Specifically, the model estimated the impact of 18 geographic source regions (which are identified in Figure 3) and 6 source sectors (EGU point, non-EGU point, on-road, off-road, area, and biogenic sources) at each ozone monitoring site in the region.

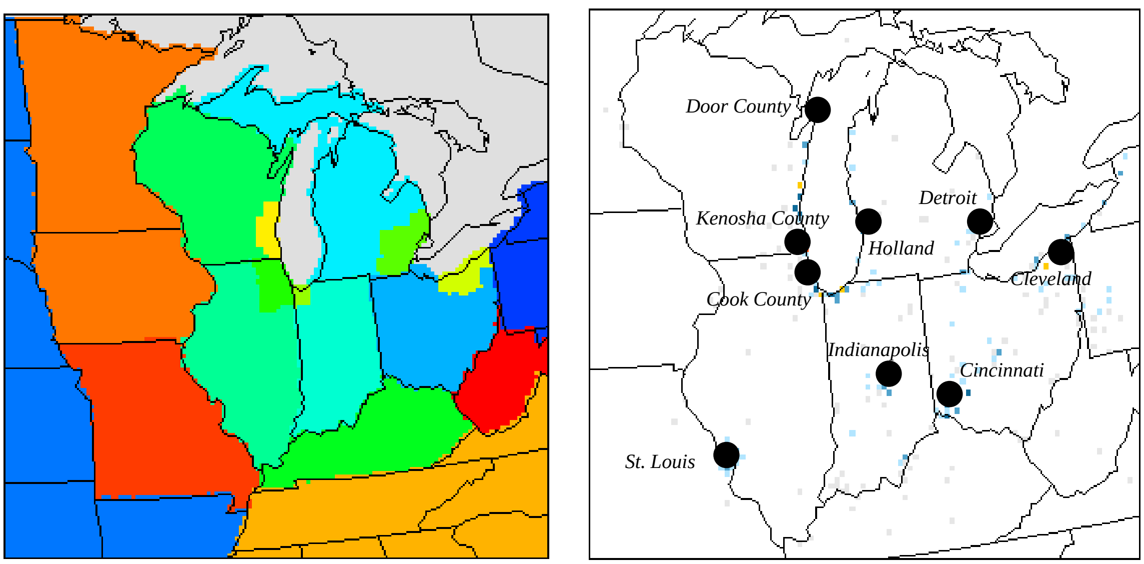


Figure 3. Source regions (left) and key monitoring sites (right) for ozone modeling analysis

Modeling results for 2012 (with "on the books" controls) are provided in Figure 4 for several key monitoring sites. For each monitoring site, there are two graphs: one showing sector-level contributions, and one showing source region and sector-level contributions in terms of percentages. (Note, in the sector-level graph, the contribution from NOx emissions are shown in blue, and from VOC emissions in green. For EGUs, several higher emitting facilities were tracked individually and their collective contribution is shown as the red portion of the EGU bar.)

The sector-level results show that on-road and nonroad NOx emissions generally have the largest contributions at the key monitor locations (> 15% each). EGU and non-EGU NOx emissions are also important contributors (> 10% each). The source group contributions vary by receptor location due to emissions inventory differences. The source region results show that nearby emissions generally have the highest impacts (e.g., the Chicago nonattainment area contributes 25-40% in the Lake Michigan area, and Cleveland nonattainment counties and other Ohio counties contribute 20 – 30% and about 15%, respectively, in northeastern Ohio).

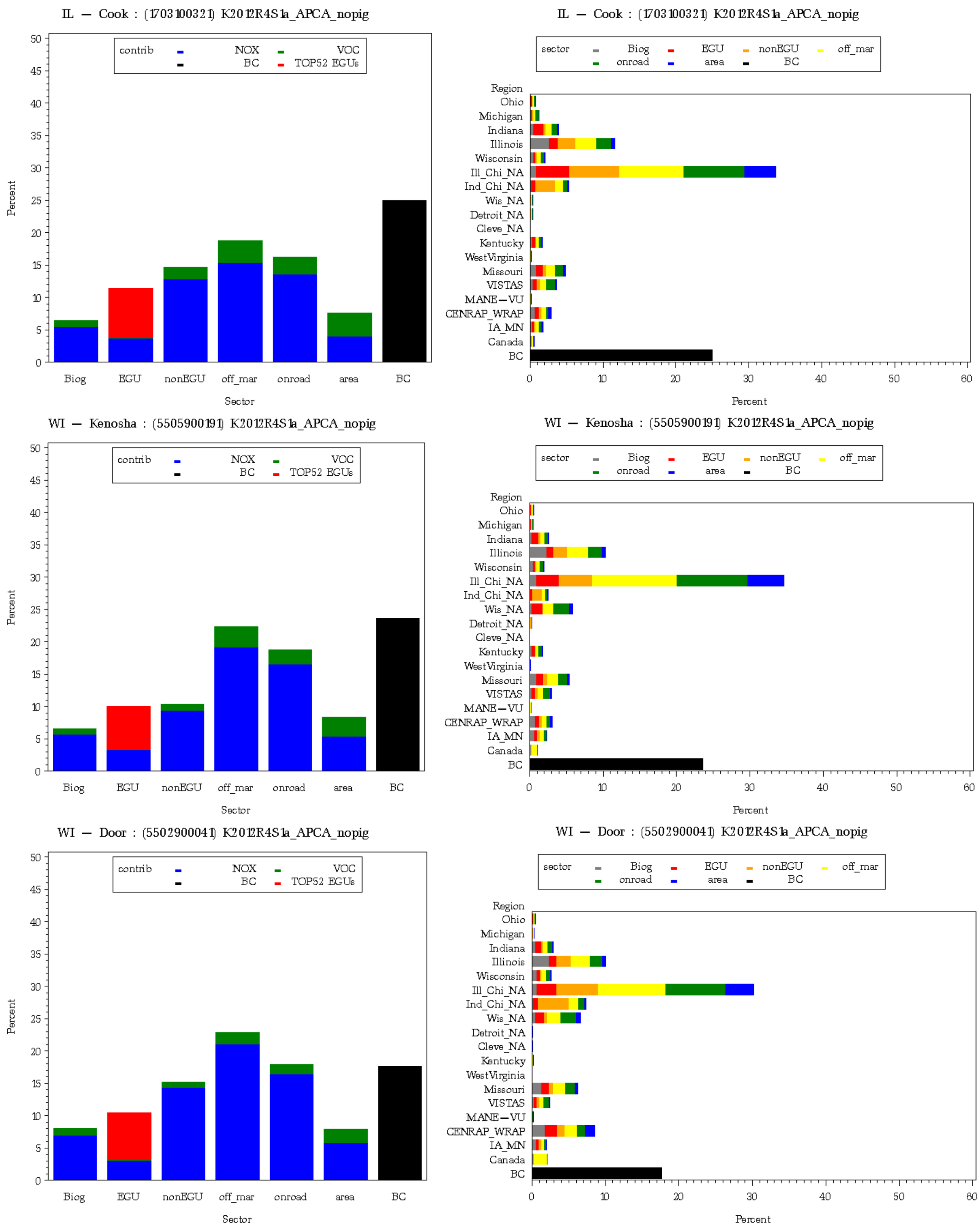


Figure 4a. Model-based ozone source apportionment results for sites in the Lake Michigan area - Cook County, IL (top), Kenosha County, WI (middle), and Door County, WI (bottom)

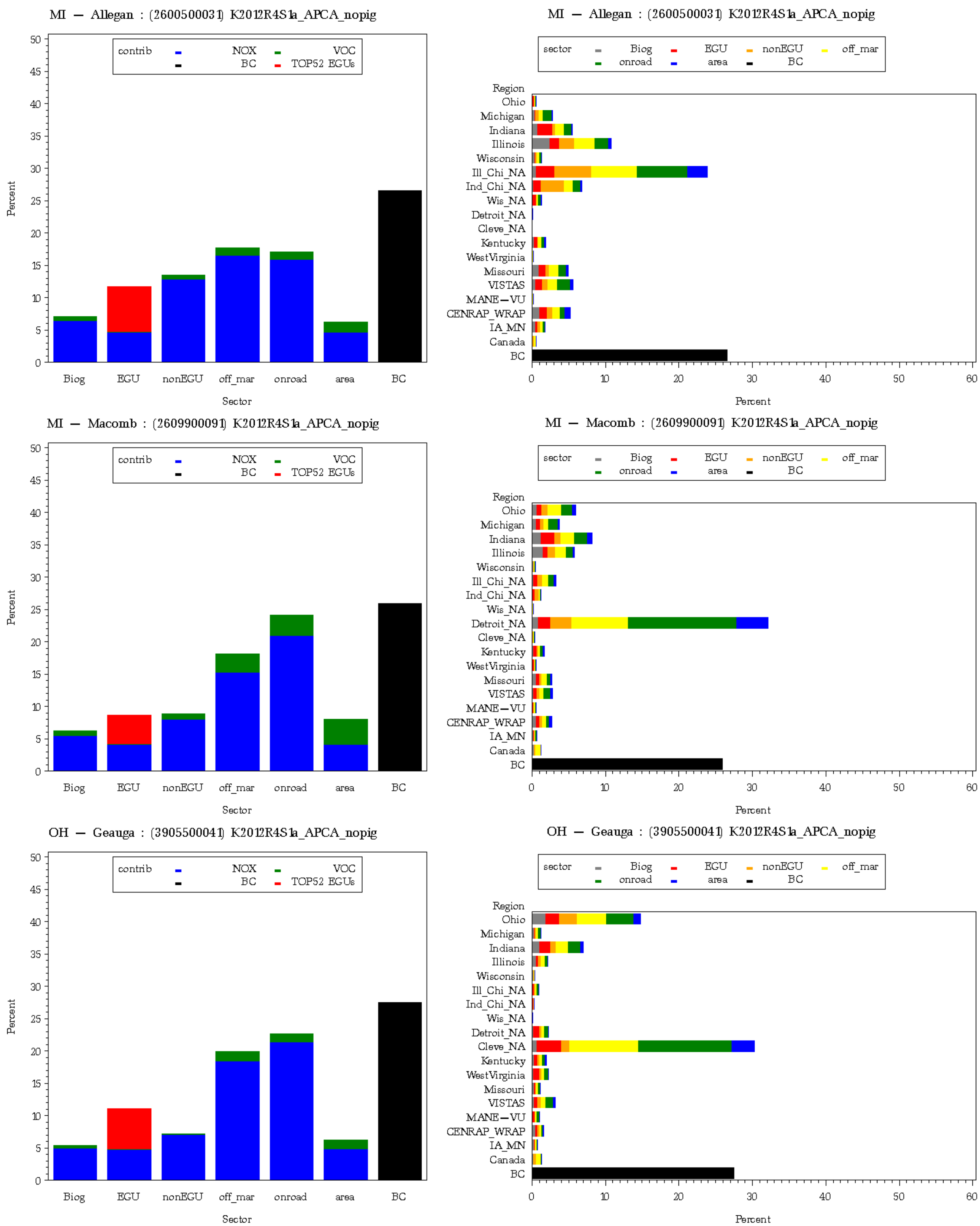


Figure 4b. Model-based ozone source apportionment results for Holland, MI (top), Detroit, MI (middle), and Cleveland, OH (bottom)

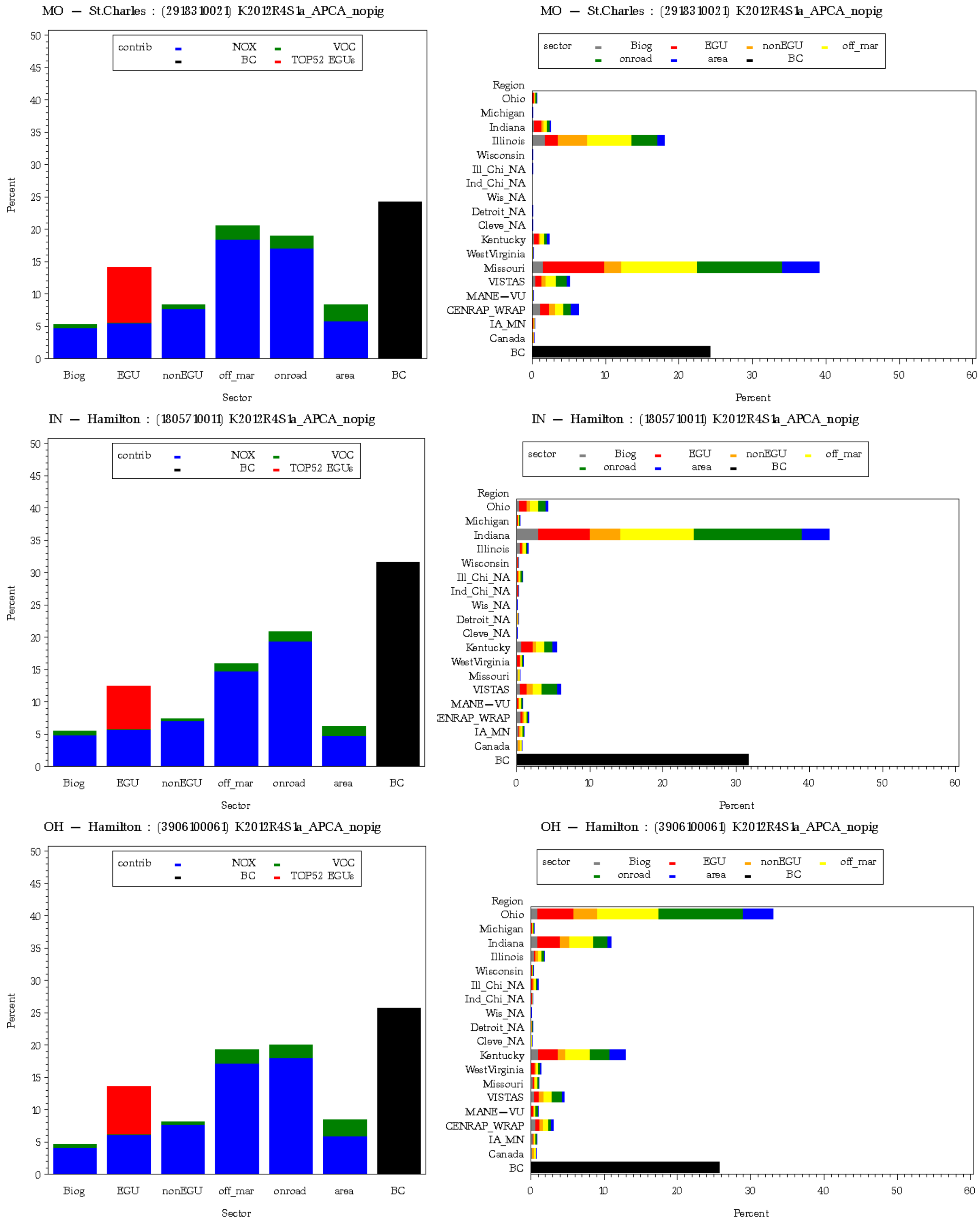


Figure 4c. Model-based ozone source apportionment results for St. Louis, MO (top), Indianapolis, IN (middle), and Cincinnati, OH (bottom)

PM$_{2.5}$

PM$_{2.5}$ is comprised of several chemical species, including ammonium sulfate, ammonium nitrate, organic carbon, elemental carbon, and soil. NOx emissions contribute to the formation of ammonium nitrate. Figure 5 shows the chemical composition of PM$_{2.5}$ across the region. Ammonium nitrate concentrations are greater in northern cities (e.g., Chicago and Detroit) compared to more southern cities (e.g., St. Louis).

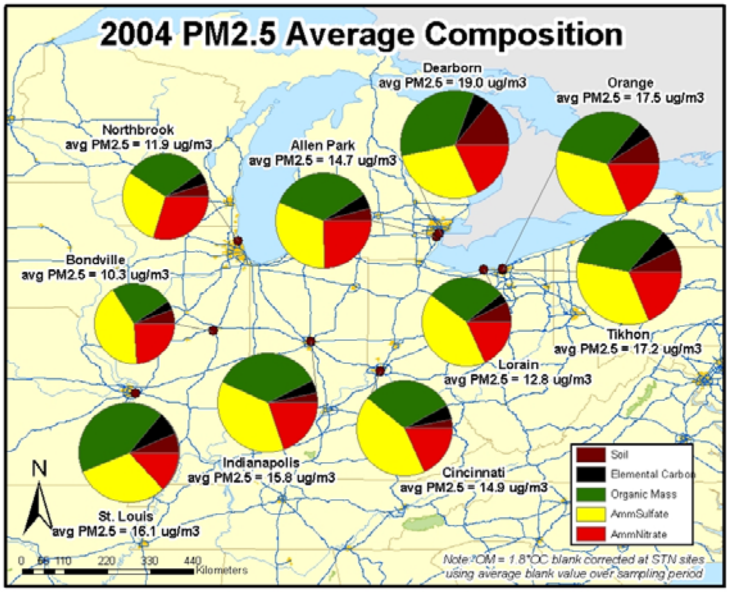


Figure 5. PM$_{2.5}$ chemical composition in the LADCO region – 2004 data

A photochemical grid model (CAMx) was applied to provide source contribution information. Specifically, the model estimated the impact of 18 geographic source regions (which are identified in Figure 6) and 6 source sectors (EGU point, non-EGU point, on-road, off-road, area, and ammonia sources) at each PM$_{2.5}$ monitoring site in the region.

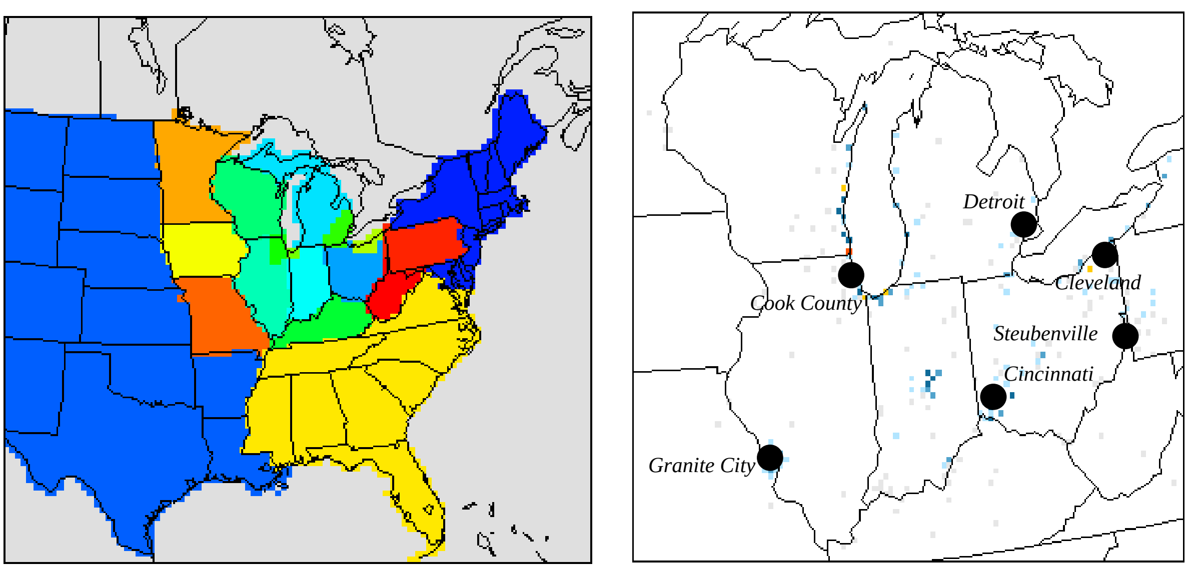


Figure 6. Source regions (left) and key monitoring sites (right) for PM$_{2.5}$ modeling analysis

Modeling results for 2012 (with “on the books” controls) are provided in Figure 7 for several key monitoring sites in the region. For each monitoring site, there are two graphs: one showing species- and sector-level contributions, and one showing source region and species-level contributions in terms of absolute modeled values.

The species- and sector-level results show that on-road and nonroad NOx emissions generally have the largest contributions to nitrate concentrations. EGU and non-EGU NOx emissions are also important contributors. The source group contributions vary by receptor location due to emissions inventory differences.

The source region results show that emissions from nearby/local sources are large contributors to $PM_{2.5}$ concentrations. There is also a sizable regional contribution.

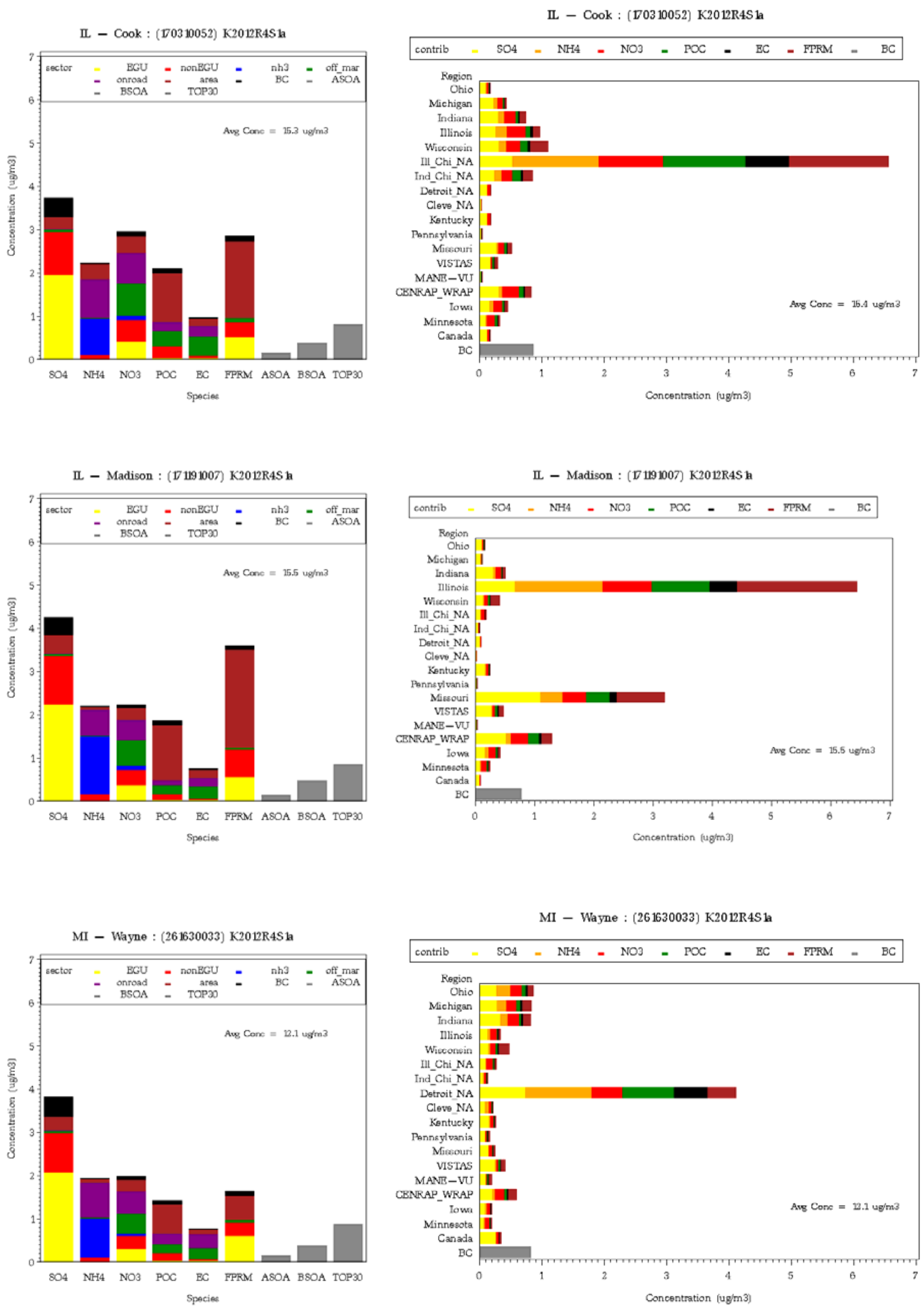


Figure 7a. Model-based $PM_{2.5}$ source apportionment results for sites in Chicago, IL (top), Granite City, IL (middle), and Detroit, MI (bottom)

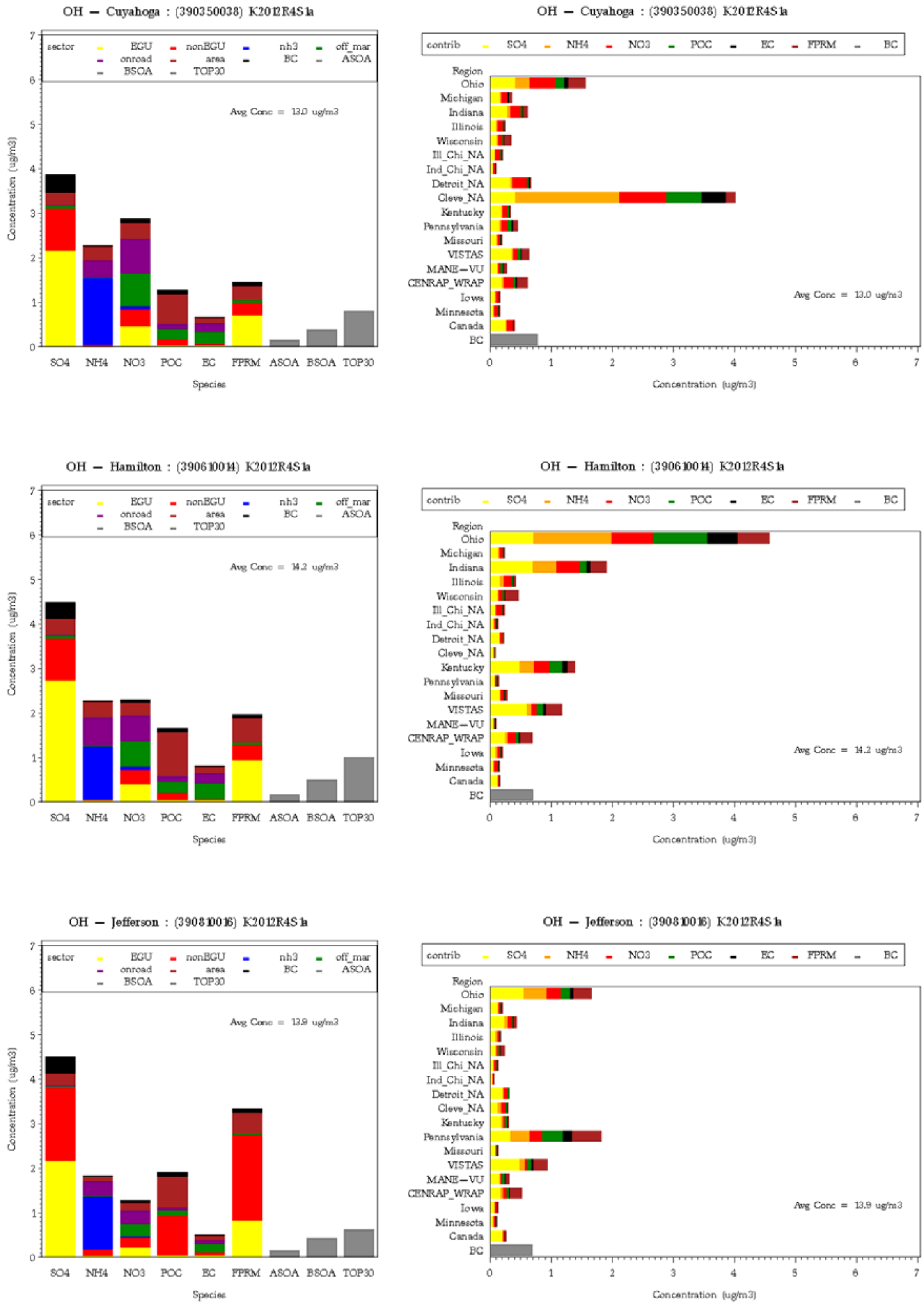


Figure 7b. Model-based $PM_{2.5}$ source apportionment results for Cleveland, OH (top), Cincinnati, OH (middle), and Steubenville, OH (bottom)

Regional Haze

A photochemical grid model (CAMx) was applied to provide source contribution information. Specifically, the model estimated the impact of 18 geographic source regions (which are identified in Figure 8) and 6 source sectors (EGU point, non-EGU point, on-road, off-road, area, and ammonia sources) at each visibility/haze monitoring site in the region.

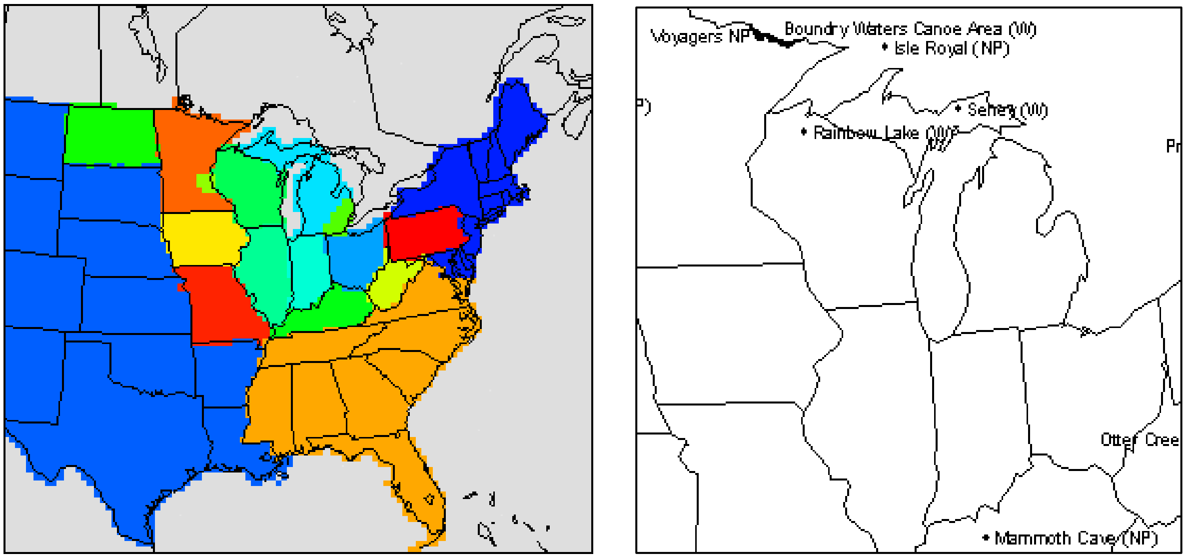


Figure 8. Source regions (left) and key monitoring sites (right) for haze modeling analysis

Modeling results for 2018 (with "on the books" controls) are provided in Figure 9 for three key monitoring sites (Class I areas) in and near the region. For each monitoring site, there are two graphs: one showing species- and sector-level contributions, and one showing source region and species-level contributions in terms of absolute modeled values.

The species- and sector-level results show that on-road and nonroad NOx emissions generally have the largest contributions to nitrate concentrations. EGU and non-EGU NOx emissions are also important contributors. The source group contributions vary by receptor location due to emissions inventory differences.

The source region results show that emissions from a number of nearby states contribute to regional haze levels.

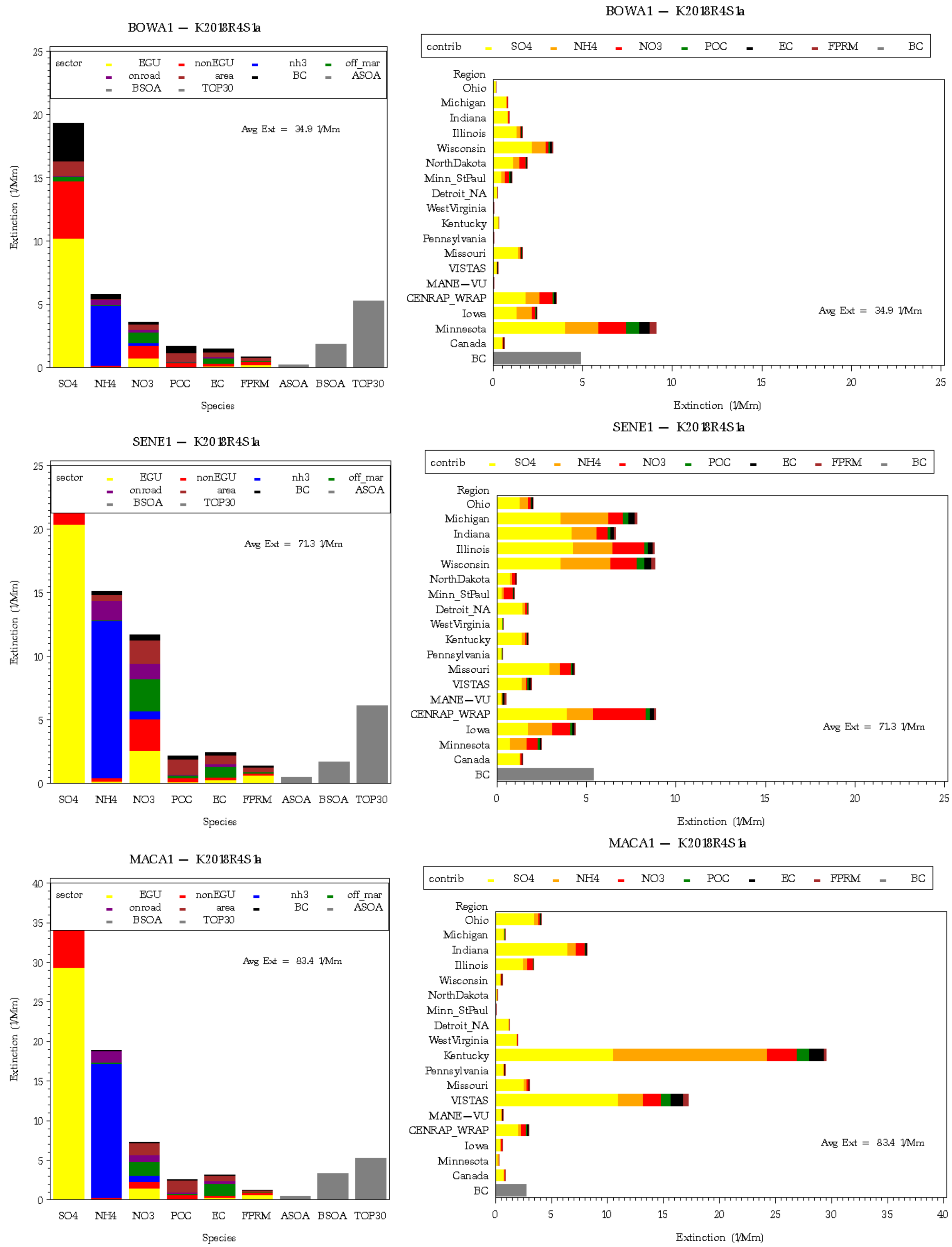


Figure 9. Model-based regional haze source apportionment results for Boundary Waters, MN (top), Seney, MI (middle), and Mammoth Cave, KY (bottom)

Summary

This document provides information on sources of NOx emissions and the effect of NOx emissions on ozone and $PM_{2.5}$ concentrations and regional haze levels. Several key findings should be noted:

- Mobile sources make-up about 60% of the regional 2009/2012 NOx emissions. LADCO's contractor is evaluating candidate NOx control measures for on-road and nonroad sources. The preliminary results indicate several concerns for these control measures: (a) relatively small reductions (i.e., an example scenario analysis showed only about a 3-4% reduction in mobile source NOx emissions), (b) uncertain effectiveness (i.e., many control programs are voluntary), and (c) high costs (i.e., the example scenario analysis costs exceed several billion dollars).

- Point sources (EGUs and non-EGUs) make-up about 35% of the 2009/2012 NOx emissions. Even though EGU emissions will decrease dramatically due to the NOx SIP Call and CAIR, EGUs still make-up 20% of the regional 2009/2012 NOx emissions. Furthermore, a significant percentage of the power generation in the region is expected to reflect only limited (combustion) controls. Application of more advanced controls (e.g., SNCR or SCR), which are proven technologies, can achieve further reductions in EGU NOx emissions

- Non-EGUs make-up 15% of the regional 2009/2012 NOx emissions. Important source categories include ICI boilers (5% of the regional 2009/2012 NOx emissions), IC engines (3%), cement manufacturing (1.3%), metal production (1.3%), and petroleum refineries (1%). For these source categories, there are known control technologies which can achieve reductions in NOx emissions from several dozen units with either no controls or only limited (combustion) controls.

Attachment B

List of Sources Affected by the NOx SIP Call

List of Sources Affected by the NOx SIP Call

Plant ID	Plant Name	Point ID	Segment	Description of the Unit	NOx Reduction (Tons/season)
027807AAC	NATURAL GAS PIPELINE CO. OF AMERICA 8310	730103540041	1	Engine 10-Eng	176
041804AAC	PANHANDLE EASTERN PIPELINE	73010573009	9	Engine 1213	173
041804AAC	PANHANDLE EASTERN PIPELINE	73010573010	10	Engine 1214	167
041804AAC	PANHANDLE EASTERN PIPELINE	73010573011	11	Engine 1215	153
041804AAC	PANHANDLE EASTERN PIPELINE	73010573012	12	Engine 1216	169
041804AAC	PANHANDLE EASTERN PIPELINE	73010573013	13	Engine 1217	171
073816AAA	NATURAL GAS PIPELINE CO OF AMERICA	851000140011	1	Engine # 12	209
073816AAA	NATURAL GAS PIPELINE CO OF AMERICA	851000140012	2	Engine # 13	211
073816AAA	NATURAL GAS PIPELINE CO OF AMERICA	851000140013	3	Engine # 14	211
073816AAA	NATURAL GAS PIPELINE CO OF AMERICA	851000140014	4	Engine # 15	195
073816AAA	NATURAL GAS PIPELINE CO OF AMERICA	851000140041	1	Engine # 9	141
073816AAA	NATURAL GAS PIPELINE CO OF AMERICA	851000140051	1	Engine # 10	261
085809AAA	ROYSTER-CLARK NITROGEN	730700330101	1	Clark Compressor C-02A	242
085809AAA	ROYSTER-CLARK NITROGEN	730700330102	2	Clark Compressor C-02B	242
085809AAA	ROYSTER-CLARK NITROGEN	730700330103	3	Clark Compressor C-02C	242
093802AAF	ANR PIPELINE CO	E-108	1	Engine E-1008	215
113817AAA	NICOR GAS	730105440021	1	Engine EC21	149
113817AAA	NICOR GAS	730105440031	1	Engine IC11	299
113821AAA	NICOR GAS	730105430021	1	Compressor EC21	317
113821AAA	NICOR GAS	730105430051	1	Compressor CC22	211
149820AAB	PANHANDLE EASTERN PIPELINE	7301057199G	3	Engine 1014	159

149820AAB	PANHANDLE EASTERN PIPELINE	7301057199I	1	Engine 1015	172
149820AAB	PANHANDLE EASTERN PIPELINE	7301057199J	1	Engine 1016	172
149820AAB	PANHANDLE EASTERN PIPELINE	7301057199K	1	Engine 1017	169
167801AAA	PANHANDLE EASTERN PIPELINE	87090038001	1	Engine 1015	152
167801AAA	PANHANDLE EASTERN PIPELINE	87090038002	1	Engine 1016	166
167801AAA	PANHANDLE EASTERN PIPELINE	87090038004	1	Engine 1017	124
167801AAA	PANHANDLE EASTERN PIPELINE	87090038005	1	Engine 1018	154
Total					**5,422**

Attachment C

List of Impacted RICE

List of Impacted RICE

Plant ID	Plant Name	Emission Point	No. of Units
091811AAB	Natural Gas Pipeline Co of America	0038	2
091811AAB	Natural Gas Pipeline Co of America	0005	1
093802AAF	ANR Pipeline Co	0003	1
127855AAB	Trunkline Gas Co	0004	1
191803AAA	Trunkline Gas Co	0010	1
031600CEV	University of Illinois At Chicago	0009	1
073816AAA	Natural Gas Pipeline Company of America	0015	1
147802AAB	Natural Gas Pipeline of America	0002	2
027807AAC	Natural Gas Pipeline Co of America	0003	1
027807AAC	Natural Gas Pipeline Co of America	0010	1
085809AAA	Royster Clark	0010	3
127855AAB	Trunkline Gas Co	0008	1
091811AAB	Natural Gas Pipeline Co of America	0034	1
093802AAF	ANR Pipeline Co	0004	1
141050AAV	Rochelle Municipal Diesel Plant	0003	1
141050AAV	Rochelle Municipal Diesel Plant	0012	1
031600CEV	University of Illinois At Chicago	0011	2
073816AAA	Natural Gas Pipeline Company of America	0001	4
073816AAA	Natural Gas Pipeline Company of America	0004	1
113817AAA	Nicor Gas	0002	1
127855AAB	Trunkline Gas Co	0005	1
113821AAA	Nicor Gas	0002	1
113821AAA	Nicor Gas	0005	1
113817AAA	Nicor Gas	0001	1
167801AAA	Panhandle Eastern Pipe Line Co	0001	2
105822AAD	Nicor Gas	0017	1
197800ABU	Trunkline Gas Co	0001	5
149820AAB	Panhandle Eastern Pipe Line Co	0003	1
027807AAC	Natural Gas Pipeline Co of America	0001	6
027807AAC	Natural Gas Pipeline Co of America	0002	1
149820AAB	Panhandle Eastern Pipe Line Co	0006	1
149820AAB	Panhandle Eastern Pipe Line Co	0007	1
041804AAC	Panhandle Eastern Pipe Line Co	0014	1
041804AAC	Panhandle Eastern Pipe Line Co	0013	1
041804AAC	Panhandle Eastern Pipe Line Co	0015	1
141050AAV	Rochelle Municipal Diesel Plant	0011	1
141050AAV	Rochelle Municipal Diesel Plant	0001	1
141050AAV	Rochelle Municipal Diesel Plant	0002	1
105822AAD	Nicor Gas	0028	3
147802AAB	Natural Gas Pipeline of America	0001	7
041804AAC	Panhandle Eastern Pipe Line Co	0012	1
041804AAC	Panhandle Eastern Pipe Line Co	0011	1
127855AAB	Trunkline Gas Co	0003	2
041808AAF	Trunkline Gas Co	0001	1

191803AAA	Trunkline Gas Co	0007	1
191803AAA	Trunkline Gas Co	0006	1
191803AAA	Trunkline Gas Co	0005	1
191803AAA	Trunkline Gas Co	0004	1
113821AAA	Nicor Gas	0001	1
197809ACP	KMS Joliet Power Partners LP	0001	4
105818AAA	Nicor Gas	0005	1
149820AAB	Panhandle Eastern Pipe Line Co	0002	2
127855AAB	Trunkline Gas Co	0001	3
073815AAC	ANR Pipeline Co	0007	1
191803AAA	Trunkline Gas Co	0001	1
191803AAA	Trunkline Gas Co	0003	1
191803AAA	Trunkline Gas Co	0002	1
149820AAB	Panhandle Eastern Pipe Line Co	0001	6
041804AAC	Panhandle Eastern Pipe Line Co	0010	1
041804AAC	Panhandle Eastern Pipe Line Co	0008	1
041804AAC	Panhandle Eastern Pipe Line Co	0009	1
041804AAC	Panhandle Eastern Pipe Line Co	0006	1
041804AAC	Panhandle Eastern Pipe Line Co	0007	1
041801AAB	Natural Gas Pipeline Co Station 203	0004	1
019065AAN	Rantoul Electric Generating Plant	0010	8
041808AAF	Trunkline Gas Co	0002	4
105818AAA	Nicor Gas	0001	1
041804AAC	Panhandle Eastern Pipe Line Co	0002	1
167801AAA	Panhandle Eastern Pipe Line Co	0008	2
105060AAI	Caterpillar Inc	0021	1
041808AAF	Trunkline Gas Co	0003	2
073815AAC	ANR Pipeline Co	0002	1
073815AAC	ANR Pipeline Co	0001	1
073815AAC	ANR Pipeline Co	0006	1
073815AAC	ANR Pipeline Co	0004	1
073815AAC	ANR Pipeline Co	0003	1
019065AAN	Rantoul Electric Generating Plant	0011	8
073815AAC	ANR Pipeline Co	0008	1
105822AAD	Nicor Gas	0029	2
093802AAF	ANR Pipeline Co	0002	1
105818AAA	Nicor Gas	0018	1
093802AAF	ANR Pipeline Co	0001	2
137867AAA	Panhandle Eastern Pipeline Co	0005	1
031600CEV	University of Illinois At Chicago	0010	1
113817AAA	Nicor Gas	0003	1
105822AAD	Nicor Gas	0019	1
141050AAV	Rochelle Municipal Diesel Plant	0006	1
141050AAV	Rochelle Municipal Diesel Plant	0008	1
105818AAA	Nicor Gas	0017	1
105060AAI	Caterpillar Inc	0030	3
137867AAA	Panhandle Eastern Pipeline Co	0006	1
167801AAA	Panhandle Eastern Pipe Line Co	0002	3

019813AAA	Peoples Gas Light & Coke Co	0070	4
141050AAV	Rochelle Municipal Diesel Plant	0004	1
137867AAA	Panhandle Eastern Pipeline Co	0004	2
051808AAB	Natural Gas Pipeline Co	0018	2
043065ADG	Nicor Gas	0003	4
051808AAB	Natural Gas Pipeline Co	0021	1
091811AAB	Natural Gas Pipeline Co of America	0040	1
091811AAB	Natural Gas Pipeline Co of America	0048	5
137867AAA	Panhandle Eastern Pipeline Co	0003	2
105060AAI	Caterpillar Inc	0031	1
095020ABS	Archer Daniels Midland Co	0028	6
091811AAB	Natural Gas Pipeline Co of America	0047	4
105822AAD	Nicor Gas	0018	1
051808AAB	Natural Gas Pipeline Co	0020	1
051808AAB	Natural Gas Pipeline Co	0019	1
019813AAA	Peoples Gas Light & Coke Co	0071	2
093802AAF	ANR Pipeline Co	0014	1
041801AAB	Natural Gas Pipeline Co Station 203	0006	3
091811AAB	Natural Gas Pipeline Co of America	0028	2
105822AAD	Nicor Gas	0020	1
105822AAD	Nicor Gas	0022	1
105822AAD	Nicor Gas	0023	1
Total Engines			**202**

List of Impacted Turbines

Plant ID	Plant Name	Emission Point	No. of Units
143065AJE	Archer Daniels Midland Co	0027	2
019010ADA	University of Illinois	0042	2
031003ADA	Alsip Paper Condominium Assn	0002	1
043801AAJ	Gas Recovery Services of Illinois, Inc	0001	3
143810AAG	Ameren Energy Medina Valley Cogen LLC	0001	3
197817AAA	Natural Gas Pipeline Co of America	0020	1
031600GKE	Calumet Peaking Facility	0001	8
197899AAC	PPL University Park LLC	0001	1
197899AAC	PPL University Park LLC	0002	1
197899AAC	PPL University Park LLC	0003	1
197899AAC	PPL University Park LLC	0004	1
197899AAC	PPL University Park LLC	0005	1
197899AAC	PPL University Park LLC	0006	1
197899AAC	PPL University Park LLC	0007	1
197899AAC	PPL University Park LLC	0008	1
197899AAC	PPL University Park LLC	0009	1
197899AAC	PPL University Park LLC	0010	1
197899AAC	PPL University Park LLC	0011	1
197899AAC	PPL University Park LLC	0012	1
043801AAJ	Gas Recovery Services of Illinois, Inc	0002	1
197800AAA	Exxon Mobil	0043	1
085809AAG	Northern Natural Gas Co	0001	1
085809AAG	Northern Natural Gas Co	0002	1
Total Turbines			**36**