ILLINOIS POLLUTION CONTROL BOARD

In The Matter of:	**)**	
Proposed New Clean Air Interstate Rule	**)**	
(CAIR) SO2, NOx Annual and NOx Ozone	**)**	No. R06-26
Season Trading Programs, 35 Ill. Adm.	**)**	(Rulemaking – Air)
Code 225. Subparts A, C, D and E	**)**	

NOTICE OF FILING

TO: See attached Service List

PLEASE TAKE NOTICE that on January 5, 2007, I caused to be filed electronically with the Office of the Clerk of the Pollution Control Board, on behalf of KINCAID GENERATION, L.L.C., the attached KINCAID GENERATION, L.L.C.'S FINAL COMMENTS with corresponding exhibits, copies of which are hereby served upon you.

By: /s/ *Katherine M. Rahill*
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I, Katherine M. Rahill, an attorney, hereby certify that I served copies of the foregoing documents via first class mail upon the parties on the attached Service List this 5th day of January, 2007.

By: ____/s/ *Katherine M. Rahill*________
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BEFORE THE ILLINOIS POLLUTION CONTROL BOARD

In The Matter of:	)	**No. R06-26**
	)	**(Rulemaking -Air)**
Proposed New Clean Air Interstate Rule	)	
(CAIR) SO2, NOx Annual and NOx Ozone Season	)	
Trading Programs, 35 Ill. Adm. Code 225.	)	
Subparts A, C, D and E.		

FINAL COMMENTS OF KINCAID GENERATION, L.LC.

NOW COMES Participant KINCAID GENERATION, L.L.C. ("Kincaid"), by and through its attorneys, JENNER & BLOCK LLP, and respectfully submits its final comments to this rulemaking. Kincaid appreciates this opportunity to comment again on these important new rules. Kincaid has been an active participant throughout this long rulemaking process – attending all the "outreach" meetings convened by the Illinois Environmental Protection Agency ("IEPA") in Springfield in January and February, participating in the Board hearings both in Springfield and Chicago, providing comment on the proposal on two separate occasions, and providing testimony at the Chicago hearing.

I. Dominion Resources, Inc. ("Dominion") owns and operates electric generating facilities in eleven states, including the 1250 megawatt coal-fired Kincaid Generation L.L.C. power plant, located in Kincaid, Illinois. Dominion also owns a 50% interest in the 1400-megawatt natural gas-fired Elwood Energy, L.L.C. combustion turbine plant, located in Elwood, Illinois.

Over the past eight years, Dominion's Kincaid station has been installing pollution controls, switching fuels and making other changes to ensure compliance with the increasingly more stringent air quality emissions limitations. To reduce sulfur dioxide emissions in order to comply with Phase II of the federal Acid Rain program, Kincaid switched in 1999 to the much lower sulfur Powder River Basin ("PRB") coal. In 2001, Kincaid began construction of two selective catalytic reduction ("SCR") systems to control nitrogen oxides ("NO_x") emissions as part of the Illinois NO_x requirements under the new IEPA Subpart W regulations. These massive control devices began operation in 2003 and have been very effective, reducing ozone season NO_x emissions by more than 85% from previous levels.

Kincaid supports the adoption of state regulations that embrace the federal Clean Air Interstate Rule ("CAIR"). Kincaid appreciates the IEPA's efforts to address the individual electric companies' particular problems associated with implementation of these important new regulations and also appreciates this opportunity to comment on the proposed regulations.

II. Subparts D (CAIR NO_x Annual Trading Program) and E (CAIR NO_x Ozone Season Trading Program) of the Illinois CAIR proposal deviate significantly from EPA's model rule and could jeopardize EPA approval of the Illinois CAIR SIP.

Kincaid does not support the IEPA proposal under Subparts D and E. Specifically, we do not support the 25% set-aside of NO_x allowances under proposed Sections 225.455 and 225.555, the so-called "Clean Air Set-Aside" ("CASA"). First, the agency has provided no justification that the level of the proposed set-aside is necessary from an air quality perspective. Second, these provisions will significantly increase compliance costs for Illinois sources and competitively disadvantage the state relative to surrounding states. Furthermore, this approach also could jeopardize USEPA approval of the Illinois CAIR SIP, and perhaps the ability of Illinois sources to participate in the federal trading program. It may also deny Illinois the economic advantages of the USEPA trading program that many other surrounding states will realize through their adoption of the USEPA rule.

In addition, we do not support the proposed withholding of allowances from the compliance supplement pool ("CSP") under Section 225.480 of the CAIR NO_x Annual Trading Program proposal. These additional NOx allowances have been provided in the federal rule to encourage early reductions during 2007 and 2008. Illinois included early reduction provisions in its rules implementing the NO_x SIP Call. These early reduction incentives not only provide companies added compliance flexibility that eases the burden once the requirements take effect, but benefit the environment as well by providing real emission reductions sooner. Given this past success, it seems counterintuitive for the agency to consider eliminating such an incentive by withholding allowances from the CSP.

III. The IEPA should justify any "beyond CAIR" NO_x reductions with a thorough modeling demonstration.

Should there remain local areas in Illinois that fail to meet the air quality standards following implementation of the CAIR regional reductions, the IEPA should thoroughly evaluate the amount of additional air quality improvement needed and the amount of emission reductions needed in the more localized nonattainment area in order to achieve the needed air quality improvements in the most cost-effective manner. Requiring all Illinois sources subject to CAIR to implement "beyond CAIR" reductions across-the-board for the purpose of resolving local problems is not reasonable or environmentally justified. Kincaid urges IEPA to conduct a thorough modeling demonstration to determine the level of reductions that may be necessary to resolve any residual non-attainment problems following implementation of the CAIR reductions. The 25% NO_x "set-aside" is unreasonably burdensome to Illinois generators and their customers and has not been demonstrated to be necessary to achieve attainment with the ambient air quality standards. As USEPA has stated, the program is designed "to balance the burden for achieving attainment between regional-scale and local-scale control programs."[1]

Therefore, for the purposes of implementation of CAIR, Kincaid does not believe it is necessary for IEPA to propose the "beyond CAIR" NO_x reductions and urges the Board to reject the IEPA proposal and, instead, approve full adoption of USEPA's federal "model rule" on the same schedule established by USEPA.

IV. Recent air quality modeling by Lake Michigan Air Directors Consortium ("LADCO") suggests additional NO_x reductions from the electric generating unit ("EGU") sector beyond the reductions expected from the federal CAIR program will not solve the residual ozone and $PM_{2.5}$ non-attainment problem in the Chicago area. A comprehensive attainment plan should be thoroughly researched and fully developed that clearly and conclusively demonstrates the level of emissions reductions needed and the source categories for which the most efficient and effective reductions can be achieved. Only when this plan has been fully developed will IEPA have the justification to proceed with "beyond CAIR" reductions.

Further EGU reductions of SO_2 and NO_x are not likely to impact $PM_{2.5}$ concentrations sufficiently to achieve attainment in any residual $PM_{2.5}$ nonattainment areas in Illinois or in other states. Accordingly, mandated beyond-CAIR EGU reductions of SO_2 and NO_x may not be necessary, cost effective or even have any beneficial effect on reducing the particle concentration of monitored $PM_{2.5}$. The $PM_{2.5}$ particle composition may well be driven by mobile sources in winter. Another source mix may drive the $PM_{2.5}$ composition in summer. Until additional speciated monitoring data is available, it is premature to require "beyond CAIR" SO_2 or NO_x reductions from EGUs because the absolute value of $PM_{2.5}$ concentrations measured in the field may not be driven by SO_2 or NO_x reductions.

[1] 70 Fed. Reg. 25166 (May 12, 2005)

Kincaid recognizes that several areas, including the Chicago MSA, may not achieve one or both of these standards following the implementation of Phase 2 of CAIR in 2015. Although the Chicago MSA, while closer to attainment, still may not reach attainment for ozone or $PM_{2.5}$, it appears that further regional reductions in the utility sector do not make a significant difference in the attainment status of the Chicago MSA. Indeed, based on one analysis presented at the October 18, 2005 Indiana Department of Environmental Management Utility Rules Workgroup meeting, further reductions in the utility sector actually cause ozone levels to increase in the Chicago MSA. Kincaid therefore supports the approach to implement CAIR essentially as established by USEPA, and then work with sources in local nonattainment areas to determine the appropriate mix of reductions needed to resolve the remaining local nonattainment area issues.

Source apportionment data provided by LADCO bears this reasoning out. Data presented at the October 18, 2005 Indiana Utility Rules Workgroup meeting clearly indicates that Illinois EGUs make up only a small part of the ozone non-attainment problem in Chicago MSA. The data indicate that 38% of the ozone comes from NO_x and VOC emissions from “Boundary Conditions” or sources outside the five-state Midwest region. More important, 26% of the ozone problem appears to come from “Illinois On-road” or mobile sources. Illinois EGU NO_x emissions make up only about 4% of the ozone contribution, behind “Illinois Non-road,” “Illinois Non-EGU,” and “Indiana On-road” sources.[2]

[2] Mark Derf, “Photochemical Modeling Update: Round 3 – 8 Hour Ozone and $PM_{2.5}$,” Presentation for the Utility Rules Workgroup, Indiana Department of Environmental Management, October 18, 2005, attached as Exhibit A.

V. The IEPA proposal to adopt "beyond CAIR" NO_x reductions through a proposed set-aside program that far surpasses that of any surrounding state places Illinois electricity consumers at a severe economic disadvantage.

The proposal to allocate 25% of Illinois' annual NO_x budget as "set-asides" for the CASA allowances will severely restrict NO_x allocations for affected units. There appears to be little chance that these allowances will ever be returned to the EGUs since the proposal calls for any NO_x allowances that remain unclaimed from the four CASA allowance pools (Energy Efficiency and Conservation/Renewable Energy; Air Pollution Control Equipment Upgrades; Clean Coal Technology; and Early Adopters) to be used to replenish each of the four CASA pools. Once the allowances in each of these pools are replenished to a level twice the amount originally designated for that pool, proposed section 225.475 (and section 225.575 of the Ozone Season rule) indicates "the Agency may elect to retire the CAIR NOx allowances that have not been distributed…" Thus, the 25% set-aside essentially becomes a 25% reduction beyond the NO_x limits in the federal CAIR rule. The equivalent NO_x limit is very close to the NO_x limit suggested by LADCO as modeling scenario "EGU1."

Recent studies have evaluated the economic impacts that the imposition of broad-based "beyond-CAIR" model rule reductions on EGU sources would have on the State of Illinois. An August 26, 2005 report prepared by BBC Research & Consulting ("BBC") of Denver, Colorado, for the Midwest Ozone Group and the Center for Energy and Economic Development indicates that imposition of "beyond-CAIR" control strategies, such as the ones described in the white paper prepared by LADCO on additional control scenarios for EGUs, could have a significant negative impact on the economies of several Midwestern states. The paper examined two scenarios referred to as "EGU1" and "EGU2." The BBC results indicate that imposition of these "beyond

CAIR" requirements on EGUs will result in the mandatory requirement of installation of controls on very small units.[3]

BBC estimated the electric rate impacts of the proposed LADCO controls and the corresponding impact of higher electric rates on the case study industries and on household spending in the five states within the LADCO region. Rate impacts were estimated by comparing the projected annual electric utility revenue requirements, including costs of compliance with the LADCO controls, with projected annual electric utility revenue requirements after compliance with CAIR. BBC examined several scenarios of LADCO controls, including with and without replacement power to compensate for early generating unit retirements under EGU1 and EGU2. BBC quantified overall effects on regional output and employment arising from the direct impacts on the case study industries and from the impacts of higher electric rates on household disposable income. Impacts were quantified using partial equilibrium analyses of each case study industry along with the IMPLAN economic input-output model. The focus of the study was on the direct and secondary (or "multiplier") effects on ten case study industries and on the portions of the economy supported by household spending. The findings of BBC are conservative, i.e., are underestimated, because impacts of higher electric rates on other industries and the commercial sector (which together account for about one-third of all electricity sales) were not included. Health- and visibility-related economic benefits of emissions reductions and the potential short-term economic effects on the construction industry from building and installing pollution control equipment were also outside the scope of the BBC study. It should

[3] "Midwest Electric Rate Impact Study," BBC Research and Consulting, Denver, Colorado, August 26, 2005, attached as Exhibit B.

be noted that the BBC study has evaluated economic impacts of the LADCO EGU1 and EGU2 scenarios that includes tighter SO_2 emissions limits, which make up the majority of these costs.

Key findings of the BBC report are as follows:

1. From a regional standpoint, electric rates in the year 2013 would be about 11 percent higher under EGU1 and 16 percent higher under EGU2 than under the CAIR Rule. Electric rates would increase in Illinois by about 9 percent under EGU1 and about 15 percent under EGU2.

2. Demand for coal mined in Illinois, Indiana and Ohio is expected to decline by 48 percent under EGU1 and 54 percent under EGU2.

3. Annual economic output in the five-state region is projected to be reduced by between $6.9 billion and $10.4 billion under EGU1 and between $9.0 billion and $14.1 billion under EGU2. The economic output of Illinois could fall by up to $2.0 billion in the year 2013.

4. Employment in the five-state region is projected to be reduced by approximately 51,000 to 69,000 jobs under EGU1 and 69,000 to 94,000 under EGU2. In Illinois, the estimated job loss ranges from 9,300 to 12,100 under EGU1 and between 13,400 and 17,600 under EGU2.

Kincaid has attempted to separate the estimated costs presented in the BBC report for compliance with only the NO_x provisions of an EGU1 scenario. While Kincaid cannot at this time provide a breakdown of the state-specific costs associated with the EGU1 NO_x reductions expected for Illinois, Kincaid can provide an estimated cost for the five-state Midwest region (Illinois, Indiana, Ohio, Michigan and Wisconsin). Kincaid consulted the analysts that provided the cost data that BBC used as input to their report and their projection for the NO_x portion of the EGU1 scenario was estimated at $865 million per year.[4] Illinois' share of these costs will be borne by the citizens and industries of Illinois – costs that states adopting the federal CAIR program will not have to bear.

VI. Kincaid supports IEPA's proposal under Title 35, Part 225, Subpart C to adopt the federal CAIR provisions for SO_2.

Kincaid supports the IEPA proposal to adopt the federal CAIR SO_2 Trading Program as part of the Illinois CAIR rule. Modeling conducted by LADCO in the fall of 2005 suggests the current $PM_{2.5}$ models are not yet sufficiently accurate to base regulatory decisions on. LADCO indicates the model "over predicts" the contribution of sulfates to $PM_{2.5}$ concentrations and "under predicts" the contribution from organic carbon.[5] The organic carbon contribution continues to be a problem with the most recent LADCO $PM_{2.5}$ model performance, described by LADCO as "very poor."[6]

[4] James Marchetti, Michael Hein and J. Edward Cichanowicz, "Evaluation of the Midwest RPO Interim Measures and EGU1 and EGU2" – presented at the June 28, 2005 Midwest Regional Planning Organization Regional Workshop, attached as Exhibit C.
[5] Kirk Baker, LADCO Round 3 (Base J) Model Performance, September 2005, attached as Exhibit D.
[6] Kirk Baker, LADCO Round 4 (Base K) Model Performance, April 2006, attached as Exhibit E.

VII. Kincaid supports a longer baseline period for determining NO_x allocations than proposed by IEPA.

Kincaid supports the five-year baseline proposed at Part 225, Subparts D and E, Sections 225.435a and 225.535a for the initial annual and ozone season allocation of NO_x allowances for the years 2009, 2010 and 2011. Kincaid does not support the proposed use of the "two most recent years of control period gross electrical output" for determining NO_x allocations for the year 2012 and after (Sections 225.435b and 225.535b). Kincaid urges IEPA to use a five-year baseline, with an average of the three highest years, throughout the annual and seasonal NO_x trading rules with periodic revisions every five or six years. This way, the allocations will be fairly distributed among affected facilities, taking into account market swings, prolonged maintenance breaks and lengthy outages to install the extensive control equipment needed to comply with these rules as well as the recently finalized mercury rules at Part 225, Subpart B.

VIII. Withholding NO_x allowances from existing sources, like Kincaid, that have already installed expensive pollution controls to reduce NO_x emissions, amounts to a "penalty" for those sources that have opted for this approach. Further, any unclaimed allowances left over in the Energy Efficiency and Conservation/Renewable Energy ("EEC/RE") set-aside should be returned to the EGUs.

As Kincaid emphasized at the Pollution Control Board hearing in Chicago, the Illinois Part 217, Subpart W NO_x rule, based on the federal NO_x SIP Call rules, is a "cap and trade" program, i.e., Illinois affected sources must meet a federal NO_x "budget" or "cap" on emissions during each ozone season (May 1 through September 30). Sources are allocated a discrete number of NO_x allowances for each ozone season and the affected sources must make up any shortfall in the number of allowances they hold versus the number of tons of NO_x the sources emitted during the ozone season. Affected sources have three options to make up any shortfall: reduce NO_x

emissions to levels below the number of eligible allowances they hold, use allowances they have "banked" through purchase or over-compliance in previous ozone seasons, or purchase/trade allowances held by other affected sources throughout the 19 eastern states under the federal NO_x SIP Call region. The Kincaid plant chose to reduce NO_x emissions at the stack rather than to rely on extra allowances purchased from other sources.

The Illinois Subpart W rules at Part 217.770 also included an opportunity for affected sources to obtain "early reduction credits" by reducing NO_x emissions to specified levels before the rules were fully effective in the ozone season of 2004.

Kincaid clearly could have relied on the purchase or trade of NO_x allowances from other facilities to comply with the Illinois Subpart W rules, including allowances from the more than 100 Dominion-owned generating units allocated NO_x allowances under the NO_x SIP Call program. Instead, both units at the Kincaid facility were equipped in 2002 with the most effective NO_x controls available – SCR. While this was certainly a business decision, it was brought about in part by the incentives presented by the early reduction credits available under Part 217.770 of the Subpart W rules. The bottom line is that emissions were reduced earlier than required and the benefits to the environment were delivered faster – a real "win-win" for Kincaid, the IEPA and the environment.

Nevertheless, the IEPA CAIR proposal summarily withdraws this important incentive for early reductions with no other explanation than "for public health and air quality improvements." [7]

[7] Section 225.480 of the proposed rule: Part 225 – Control of Emissions from Large Combustion Sources, May 30, 2006.

Kincaid urges the Board to restore the allowances for the CSP in order to promote early compliance that will provide environmental benefits to accrue and allow affected facilities to properly plan and implement compliance strategies. Withdrawing these early reduction provisions removes the incentive for sources to reduce NOx emissions in the non-ozone season in 2007 and 2008 (by operating SCRs year-round).

At the October Illinois Pollution Control Board hearings in Springfield, the IEPA maintained that the 25% CASA does not restrict the allowance market:

> "It is very important to note that a set-aside is not the equivalent of lowering the overall budget because the allowances usually remain in the market. While the recipients of the set-aside allowances are free to hold, sell, or retire the allowances as they see fit, it is far more likely that they would offer to sell the allowances in the market in order to realize a financial benefit. As a result, the recipients have an additional source of funding for their projects, and existing sources continue to have a pool of allowances they can utilize if needed to meet their requirements, and the total amount of emissions remains at or below the budgeted amount."[8]

This explanation gives no consideration of the impact withdrawing these allowances have on the market-based principles of the federal CAIR rule. Withholding the additional 25% of the NO_x allowance budget significantly impacts the economics of the rule for EGUs. Under the federal model rule, the allowances are allocated to affected sources based on the highest three years of heat input over of the course of a five year period. Set-asides are presented in the model rule as an option states may adopt, but nowhere suggests such a dramatic set-aside. Indiana, for example, has recently finalized its CAIR rule with a 4½% set-aside for new sources and a ½% set-aside for energy efficiency/renewable energy projects. For Kincaid, the 30% set-aside equates to an annual allowance surrender of 1625 annual trading program allowances and 601

[8] Testimony of James Ross, Manager-Division of Air Pollution Control, IEPA, October 10, 2006.

ozone season trading program allowances or, in today's market, about $2.5 million per year. Under the IEPA proposal, if Kincaid needed to purchase back these allowances (which under the federal model rule would have been directly allocated to Kincaid), the net financial impact would be $5 million per year.

The unfortunate final result will ultimately fall on the businesses, factories and institutions that use electricity in Illinois, thereby, disproportionately impacting Illinois competitively with surrounding states that are adopting CAIR rules that more closely resemble the federal approach.

IEPA has suggested in its testimony in Springfield that the allowances will remain available in the market for developers as "an additional source of funding for their projects," and that "existing sources continue to have a pool of allowances they can utilize if needed to meet their requirements." The IEPA proposal then establishes the largest single set-aside of the five regulatory proposals discussed for EEC/RE projects, with 12%. Under the NOx SIP Call, several states (including neighboring Indiana and Ohio) found that many of the EEC/RE allowances were left unclaimed and eventually returned to the utilities. The IEPA proposal states that the agency "may elect to retire" the unclaimed allowances. Since the largest pool of CASA allowances in the IEPA proposal is designated for the EEC/RE set-aside, which has historically been under-subscribed under the NO_x SIP Call experience, we expect many of the CASA set-asides for EEC/RE projects to go unclaimed.

Kincaid urges the Board to reject the 30% NO_x set-aside in favor of a set-aside consistent with the federal model rule or some other more reasonable approach, and, regarding the EEC/RE set-aside, to adopt provisions that would return any allowances not claimed by EEC/RE projects to the EGUs. This approach would free up some allowances that may go unclaimed but still offer incentives for these projects. To effect this change, Kincaid suggests section 225.475(b)(4) of the proposed Subpart D: CAIR NO_x Annual Trading Program be amended as follows:

> "If allowances still remain undistributed after the allocations and distributions in the above subsections are completed, the Agency may elect to retire any CAIR NO_x allowances**, with the exception of allowances assigned to the Energy Efficiency and Conservation/Renewable Energy set-aside,** that have not been distributed to any CASA category, to continue progress toward attainment or maintenance of the National Ambient Air Quality Standards pursuant to the CAA. **Allowances from the Energy Efficiency and Conservation/Renewable Energy set-aside that remain undistributed shall be distributed to each CAIR NO_x unit in accordance with section 225.440."**

Kincaid suggests similar changes in section 225.575(b)(4) of the proposed Subpart E: CAIR NO_x Ozone Season Trading Program:

> "If allowances still remain undistributed after the allocations and distributions in the above subsections are completed, the Agency may elect to retire any CAIR NO_x allowances**, with the exception of allowances assigned to the Energy Efficiency and Conservation/Renewable Energy set-aside,** that have not been distributed to any CASA category, to continue progress toward attainment or maintenance of the National Ambient Air Quality Standards pursuant to the CAA. **Allowances from the Energy Efficiency and Conservation/Renewable Energy set-aside that remain undistributed shall be distributed to each CAIR NOx Ozone Season unit in accordance with section 225.540."**

As we have stated, Kincaid installed SCRs on both units at Kincaid in 2002. SCR is widely accepted as the most effective control for NO_x emissions from coal-fired utility boilers. This equipment has provided up to a 90% reduction in NO_x emissions during the past five ozone seasons of 2002 through 2006, enabling Kincaid to over-comply with the Illinois Subpart W rules. Kincaid is expecting that this equipment will provide the year-round NO_x reductions needed to comply with the upcoming CAIR reductions. However, the current Illinois CAIR proposal, with the 25% CASA, allocates 5% of the Illinois NO_x budget for both the annual and ozone season trading program for “air pollution control equipment upgrades” including “installation of selective catalytic reduction.”[9]

Because the eligibility to apply to this “air pollution control equipment upgrade” set-aside apparently hinges on installation of new controls on an existing source, it appears the SCRs at Kincaid would not be eligible for these allowances. This is unfair. Operation of the Kincaid SCRs on a year-round basis will require a dramatic expansion of the operations of this equipment, increasing significantly the costs for ammonia, catalysts, and other variable costs for operating the SCRs. Kincaid expects the year-round SCR operation to significantly increase “parasitic” loads on the plant, as well, primarily from increased fan loads.

Allowances were intended to help companies offset these economic burdens, and Kincaid does not believe that Illinois should disproportionately burden its electric generators.

Excluding existing air pollution control equipment that must be operated on a year-round basis following adoption of the proposed rule from applying for allowances from the “air pollution control equipment upgrade” set-aside is unfair and Kincaid urges the Board to change the eligibility so that these existing controls are included. Kincaid suggests the proposed rule be amended at §225.460(c)(1) as follows:

> “Air pollution control equipment upgrades at existing coal-fired electric generating units, as follows: installation of flue gas desulfurization (FGD) for control of SO_2 emissions; installation of a baghouse for control of particulate matter emissions; and installation of ***or extended operation of existing*** selective catalytic reduction (SCR), selective non-catalytic reduction (SNCR), or other add-on control devices for control of NO_x emissions.”

[9] Section 225.460(c)(1)of the proposed rule: Part 225 – Control of Emissions from Large Combustion Sources, May 30, 2006.

IX. Kincaid supports USEPA's position that the CAIR rulemaking does not require states to prepare an attainment SIP to comply with CAIR and the attendant emission reductions are not designed to result in attainment of the NAAQS.

As EPA noted in its CAIR preamble:

> "The EPA's CAIR and the previously promulgated NO_X SIP Call reflect EPA's determination that the required SO_2 and NO_X reductions are sufficient to eliminate upwind States' significant contribution to downwind nonattainment. These programs are not designed to eliminate all contributions to transport, but rather to balance the burden for achieving attainment between regional-scale and local-scale control programs."[10]

X. The Board has failed to evaluate the combined impact of CAMR and CAIR.

The Board has failed to evaluate the technical feasibility and economic reasonableness of simultaneous compliance with two contemporaneously adopted regulations (CAIR and CAMR), where both regulations impose unique impacts on a specific industrial sector: coal-fired electric generating units. There is no evidence in the record of either regulatory proceeding that it is technically feasible and economically reasonable for the affected facilities to comply simultaneously with both regulations. Kincaid has provided information in both regulatory proceedings that the economic impact of the individual and combined regulations is unreasonable. The Board's failure to evaluate the simultaneous impact of both rules is not consistent with Illinois law. Commonwealth Edison Company, v. Pollution Control Board, 25 Ill.App.3d 271, 323 N.E.2d 84 (First District, 1975), (aff'd 62 Ill.2d 494, 343 N.E.2d 4 (1976)); and Illinois State Chamber Of Commerce, v. Pollution Control Board 67 Ill.App.3d 839, 384 N.E.2d 922 (First District, 1978).

[10] 70 Fed. Reg. 25166

Kincaid supports implementation of the federal CAIR and urges the Illinois Pollution Control Board to adopt regulations that follow the CAIR principles.

Respectfully submitted,

Kincaid Generation, L.L.C.

by: /s/ *Bill S. Forcade*

One of Their Attorneys

Dated: January 5, 2007

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Photochemical Modeling Update: Round 3 - 8 hour Ozone and $PM_{2.5}$

Utility Rules Workgroup

IDEM, OAQ

October 18, 2005

Round 3: Base J Emissions Improvements from Round 2: Base I Emissions

- Midwest Regional Planning Organizations (RPO) states updated their point, area and mobile source inventories.
- Surrounding Regional Planning Organizations (RPO) 2002 inventories were included for 2002 base case: VISTA (southeast US), CENRAP (central US), WRAP (western US), MANEVU (northeast US).
- Revised growth and control factors for future year modeling.
- Updated IPM modeling was included.
  - IPM is a multi-regional model of the U.S. electric power sector. It provides forecasts of least-cost capacity expansion, electricity dispatch, and emission control strategies for meeting environmental constraints. IPM can be used to evaluate the cost and emissions impacts of proposed policies to limit emissions of sulfur dioxide (SO2) and nitrogen oxides (NOx) from the electric power sector.
  - Changes in fuel, electricity and emissions markets were included in the revised IPM modeling for LADCO's Base I emission inventories.

Explanation of different LADCO modeling scenarios

- **R3S1** – Controls in place already (i.e. NOx SIP Call, Fuel and Engine Standards, etc)
- **R3S2** – R2S1 controls plus anticipated controls by 2010 (i.e. CAIR rule)
- **R3S4C** – R3S2 plus EGU2 controls in 5-state MRPO region
  - EGU2 = 2009 emissions of SOx of 0.24 lb/MMBtu and NOx of 0.12 lb/MMBtu (IN, IL, MI, OH, WI)
  - Ozone modeling results show a 0.4 to 2 ppb decrease with the higher decreases taking place in southern and central Indiana.
  - $PM_{2.5}$ modeling results show a 0.9 to 1.4 ug/m3 decrease with the higher decreases taking place in southern and central Indiana.
- **R3S4D**– R3S2 plus EGU2 controls in 12-state region (MRPO region plus MN, IA, MO, TN, KY, WV, PA)
  - EGU2 = 2009 emissions of SOx of 0.24 lb/MMBtu and NOx of 0.12 lb/MMBtu (MRPO region plus MN, IA, MO, TN, KY, WV, PA)
  - Modeling results show a 0.6 to 2.5 ppb ozone decrease with the higher decreases taking place in southern and central Indiana.
  - $PM_{2.5}$ modeling results show a 1.1 to 1.8 ug/m3 decrease with the higher decreases taking place in southern and central Indiana.

LADCO'S Round 3 Modeling Results for Ozone

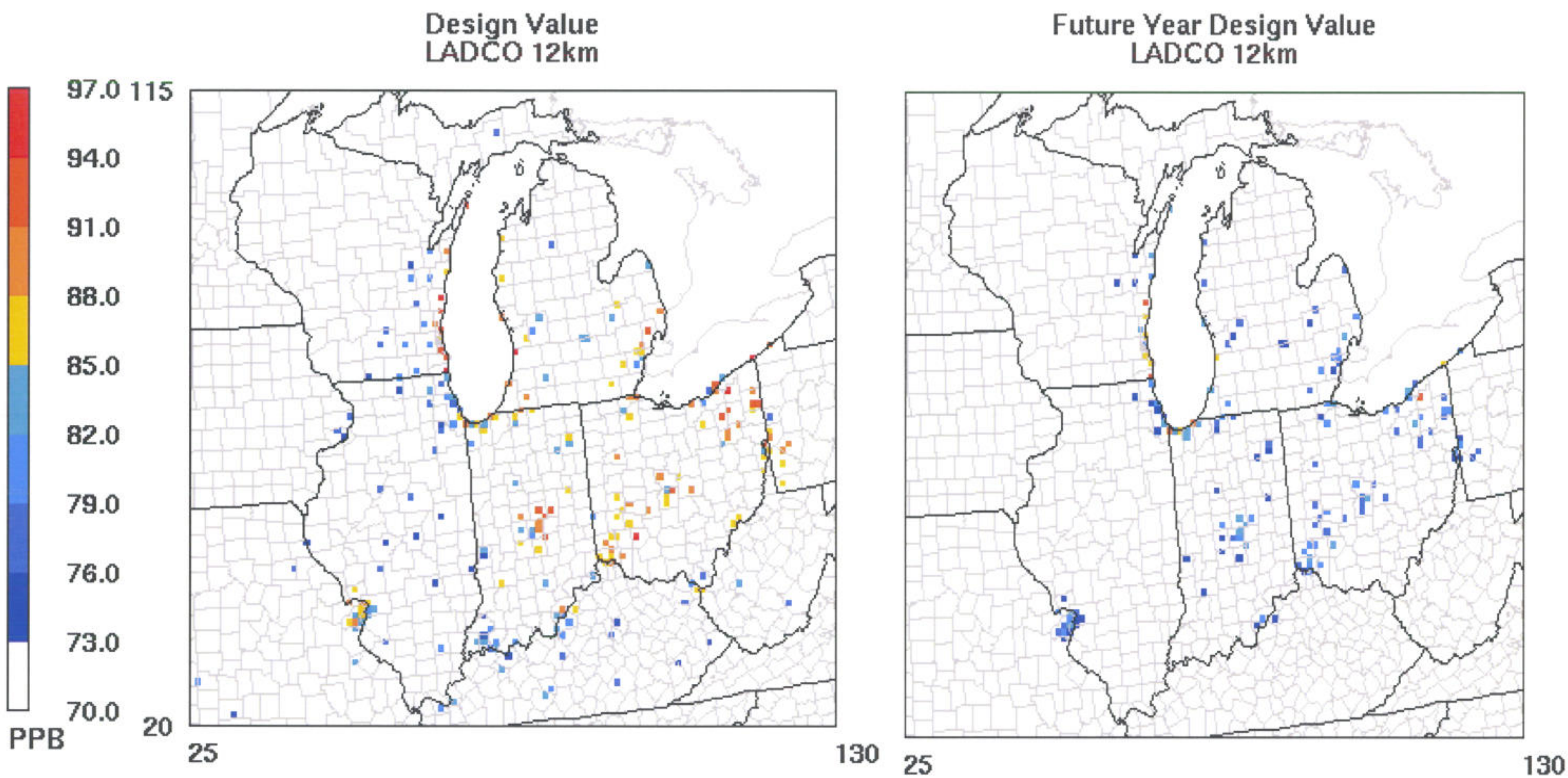
Indiana Ozone Monitors for Attainment Determinations

concentrations are parts per billion (ppb)			00-04	2009			2012	2018
Monitor	**Monitor Site**	**County**	**AVGDV**	**R3S2**	**R3S4C**	**R3S4D**	**R3S2**	**R3S2**
180030002	Leo	Allen	**87**	77.6	77.1	76.9	76.2	71
180110001	Whitestown	Boone	**88**	79	78.1	77.9	78	73
180150002	Flora	Carroll	83	73.7	72.8	72.5	72.3	66.8
180190003	Charlestown	Clark	**90**	79.5	78.9	77.8	77.5	71.1
180350010	Albany	Delaware	**85.5**	75.8	75.1	74.8	74.2	68.7
180390007	Bristol	Elkhart	**87**	77.7	77.1	77.0	76.5	72.1
180431004	New Albany	Floyd	84.3	74.8	74.3	73.1	73.2	67.6
180550001	Plummer	Greene	**87**	75.5	73.4	73.0	74.5	66
180571001	Noblesville	Hamilton	**93.7**	84.8	84	83.8	83.9	79
180590003	Fortville	Hancock	**91.3**	82.4	81.7	81.4	81.5	76.7
180630004	Avon	Hendricks	84.7	75.8	74.6	74.3	74.9	69.9
180690002	Roanoke	Huntington	83.3	73.8	73.1	72.8	72.3	67.1
180710001	Brownstown	Jackson	83.3	72.1	71.2	70.6	70.5	65
180810002	Trafalgar	Johnson	**85.3**	75.2	73.9	73.5	74	68.4
180892008	Hammond	Lake	**88.3**	**90.2**	**89.8**	**89.6**	**91.7**	**92.2**
180910005	Michigan City	LaPorte	**90.3**	**89.5**	**89**	**88.8**	**89.9**	**87.9**
180950010	Emporia	Madison	**91.7**	81.9	81.1	80.8	80.5	74.8
180970050	Fort Harrison	Marion	**90**	82.1	81.3	81.0	81.7	77.5
181090005	Monrovia	Morgan	85	75.3	73.6	73.3	74.3	68.6
181270024	Ogden Dunes	Porter	**86.3**	**87.8**	**87.4**	**87.2**	**88.7**	**87.7**
181290003	St. Phillips	Posey	84	72.3	71.5	70.8	71.1	65.8
181411007	Granger	St. Joseph	**90.3**	80.3	79.7	79.5	79.1	74.9
181450001	Fairland	Shelby	**91.3**	82.1	81	80.7	81.2	75.9
181630012	Evansville	Vanderburgh	82.7	71.1	70.3	69.6	69.9	64.4
181670024	Sandcut	Vigo	**85**	75.6	73.7	73.4	74.9	69.2
181730008	Boonville	Warrick	80.3	69	67.9	67.1	67.9	62.2

4

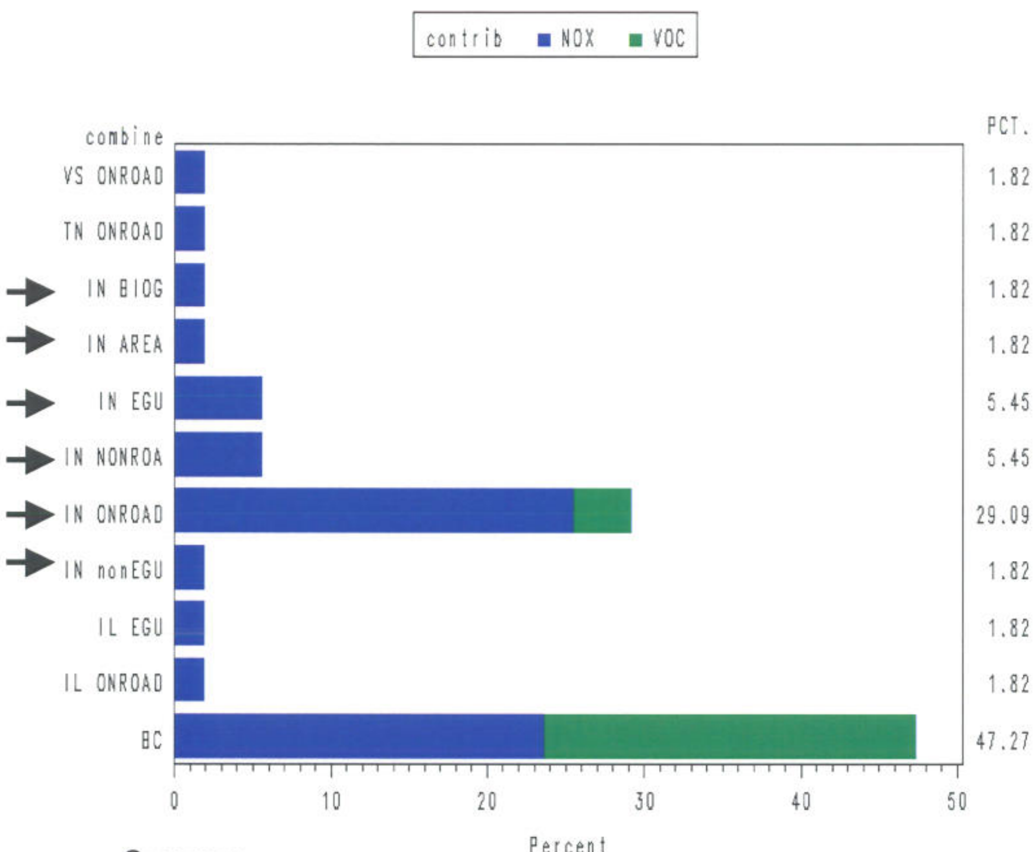
LADCO'S Round 3 Modeling Results for PM2.5								
Indiana PM2.5 Monitors for Attainment Determinations								
concentrations are in micrograms per cubic meter (ug/m3)			00-04	2009			2012	2018
Monitor ID	Monitor Name	County	AVGDV	R3S2	R3S4C	R3S4D	R3S2	R3S2
180030004	Beacon St.	Allen	14.4	12.9	11.8	11.6	12.6	11.5
180190006	Pfau	Clark	**16.5**	14.1	12.8	12.4	13.6	12.3
180350006	Muncie Central	Delaware	14.3	12.7	11.5	11.2	12.3	11.2
180372001	200 W. 6th St.	Dubois	**15.8**	13.5	12.2	11.8	13.1	11.9
180390003	Pierre Moran	Elkhart	15	13.7	12.5	12.4	13.4	12.4
180431004	Green Valley	Floyd	14.9	12.5	11.3	10.8	12.1	10.9
180670003	215 Superior	Howard	14.6	13.1	11.8	11.5	12.7	11.7
180891016	Federal Bldg	Lake	**15.7**	14.8	13.7	13.5	14.6	14.4
180910012	LaPorte	LaPorte	13.4	12.4	11.3	11.1	12.1	11.4
180950009	Anderson	Madison	14.4	12.8	11.6	11.3	12.4	11.3
180970083	E. Michigan St.	Marion	**16.4**	14.7	13.4	13.1	14.3	13.1
181270024	Ogden Dunes	Porter	13.8	13	12	11.9	12.9	12.6
181411008	South Bend	St. Joseph	14.1	12.9	11.8	11.6	12.6	11.7
181570007	Fire Station	Tippecanoe	14.6	13.1	11.8	11.6	12.8	11.6
181630016	Univ. of Evansville	Vanderburgh	**15.3**	13.3	12.1	11.6	12.9	12.1
181670018	Lafayette St.	Vigo	14.4	12.8	11.4	11.1	12.5	11.2

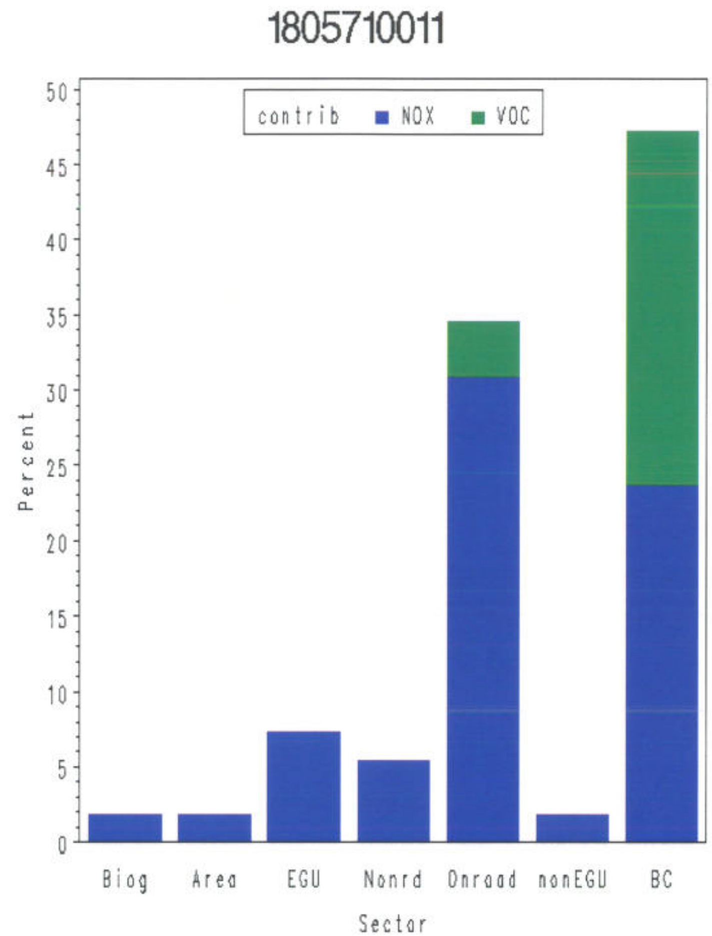
Future Year 2009 for Ozone - R3S2



ROUND 3

Source Apportionment - Ozone modeling results for Hamilton Co. IN





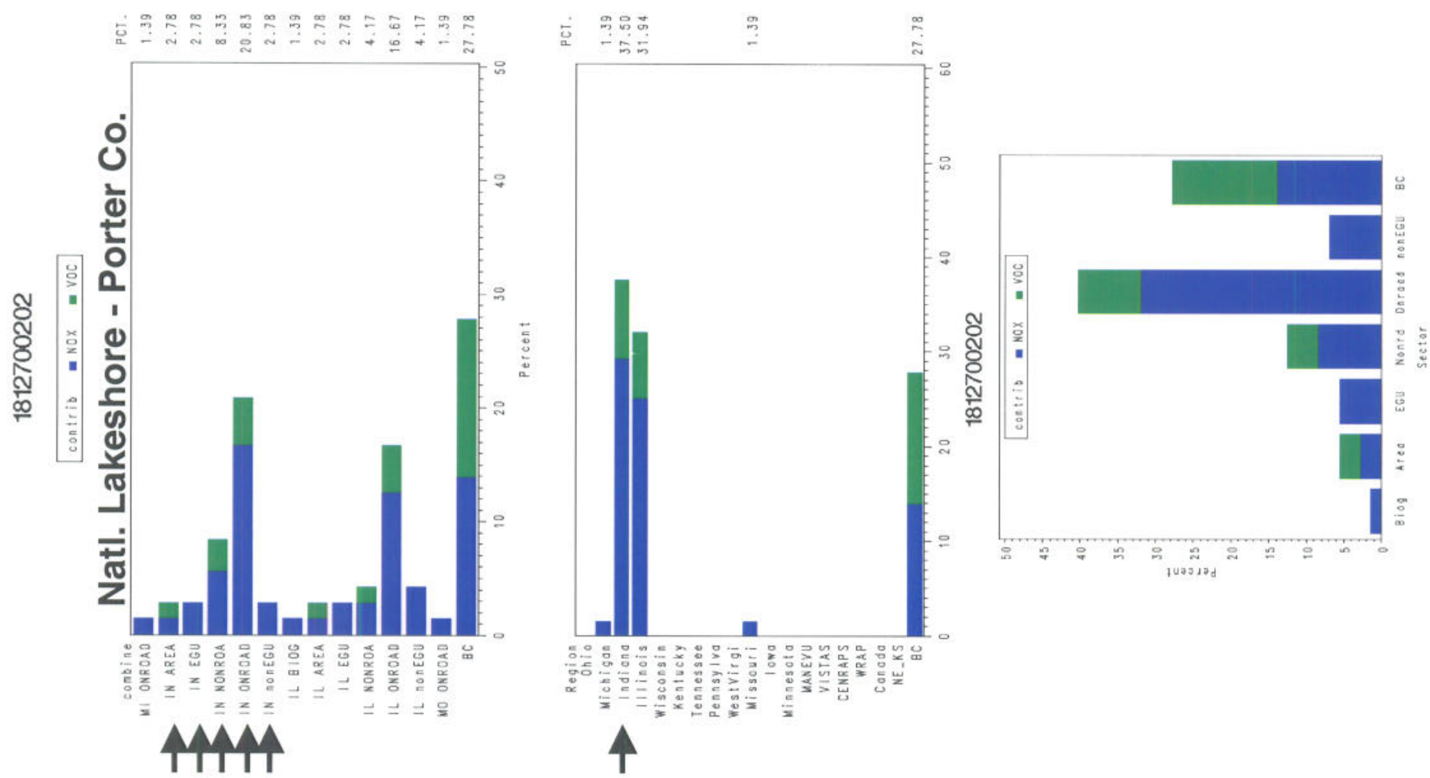
Summary

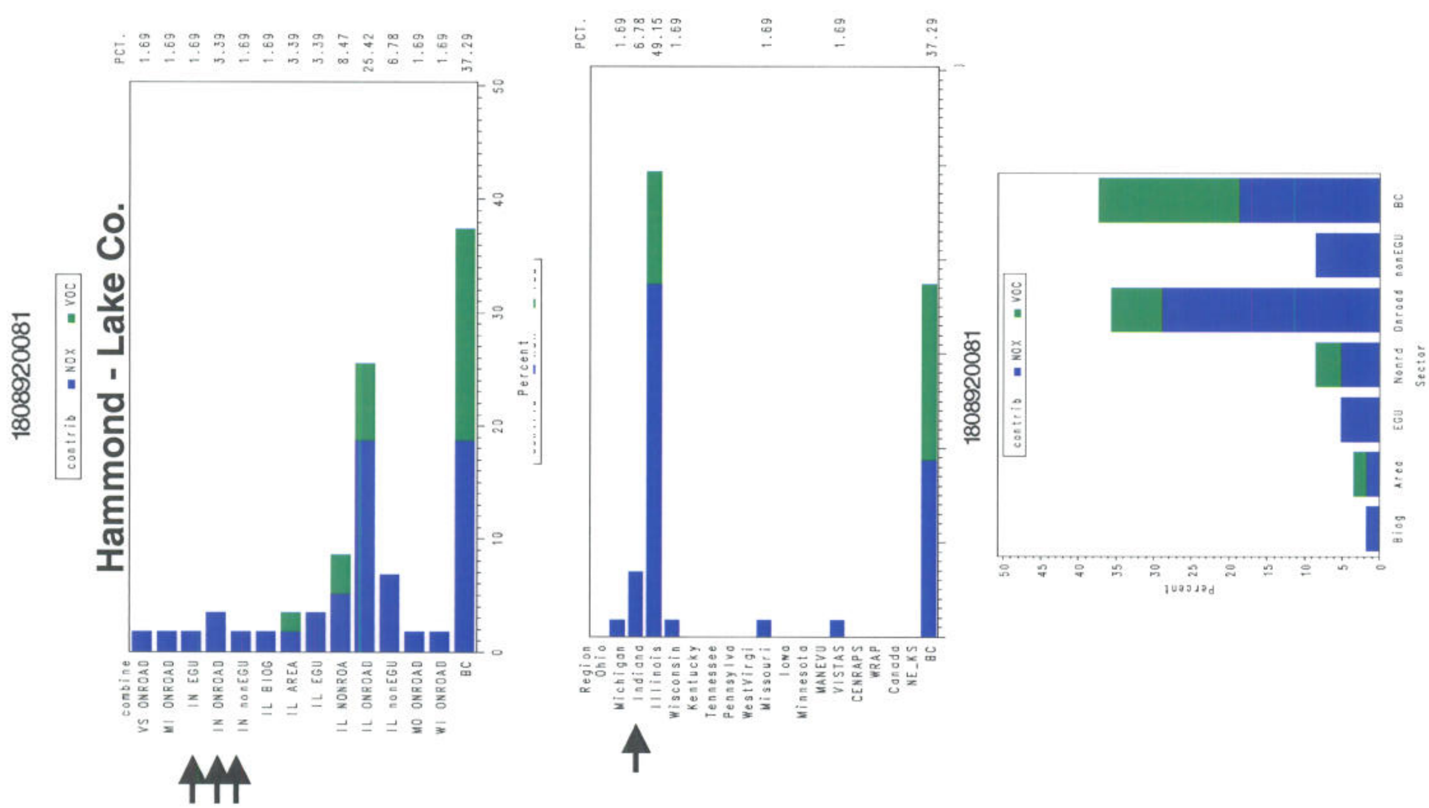
Boundary conditions (transport of ozone/ozone precursors) account for ~ 50% of ozone at Noblesville ozone monitor

Indiana onroad emissions account for ~ 30% of ozone at Noblesville ozone monitor

Indiana nonroad emissions account for ~ 5.5% of ozone at Noblesville ozone monitor

Indiana EGU emissions account for ~ 5.5% of ozone at Noblesville ozone monitor


1812700202
Natl. Lakeshore - Porter Co.
contrib ■ NOX ■ VOC
Percent
Sector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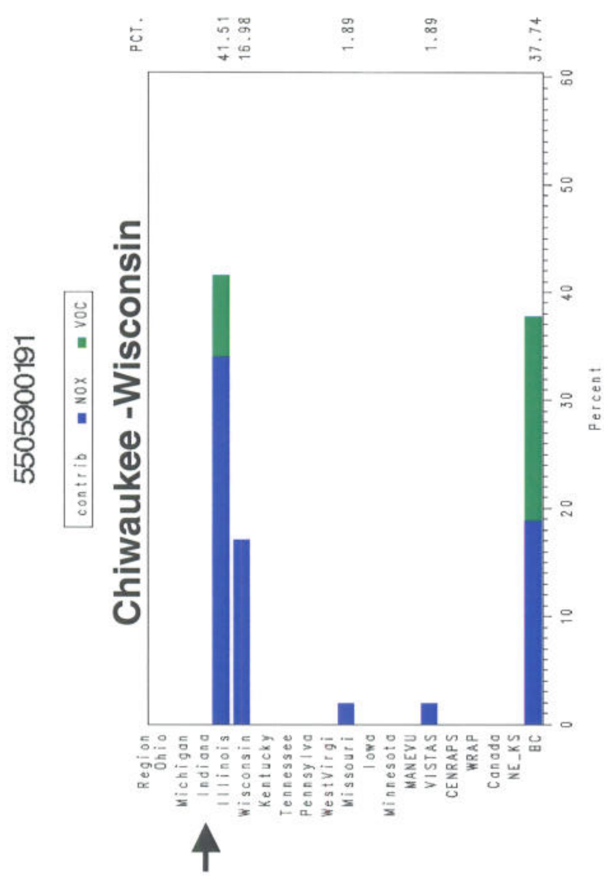
Hammond - Lake Co.
contrib ■ NOX ■ VOC
Percent
Sector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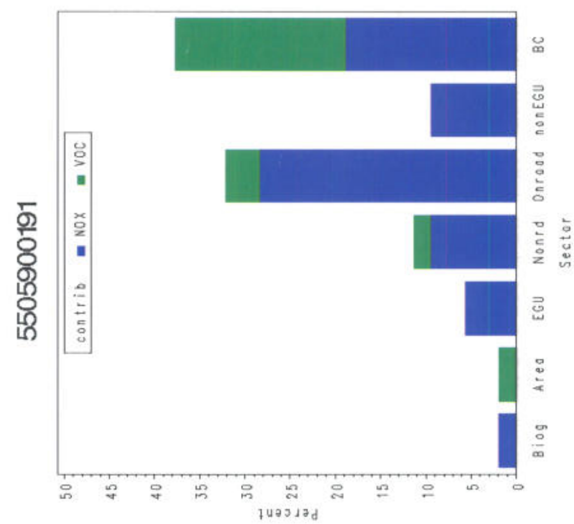
Chiwaukee -Wisconsin
contrib NOX VOC
Percent
PCT.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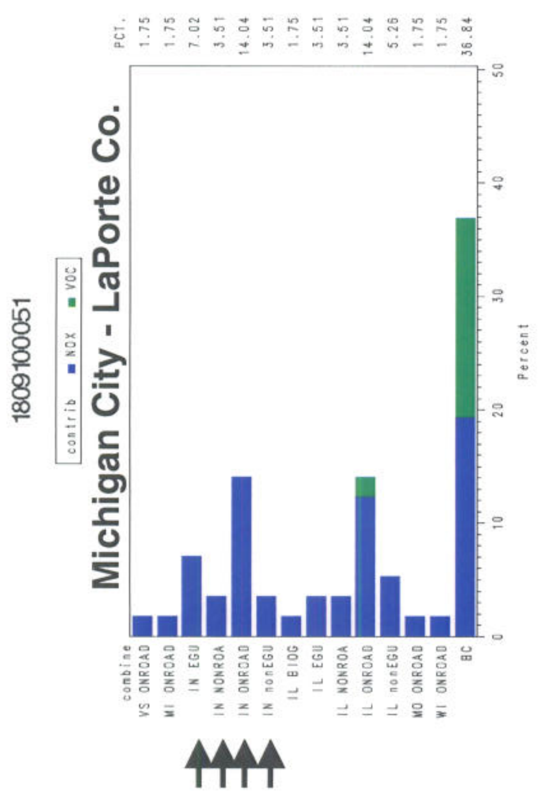
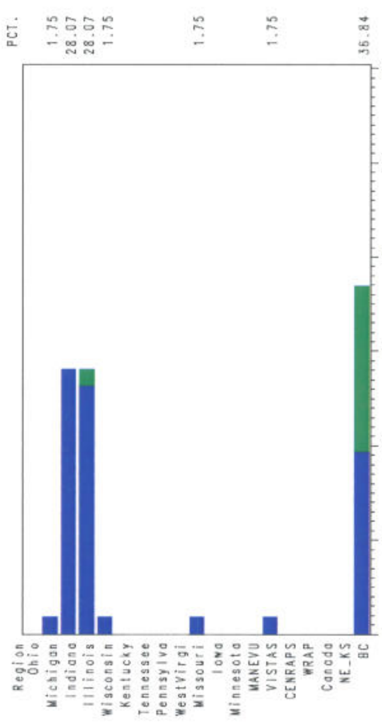
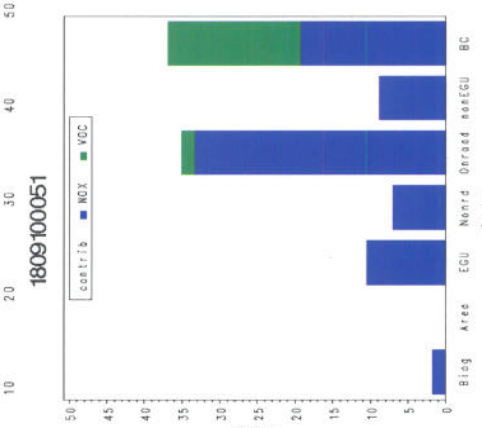
contrib NOX VOC
Percent
Sector
Biog Area EGU Nonrd Onroad nonEGU BC


1809100051
Michigan City - LaPorte Co.
contrib NOX VOC
Percent
PCT.


Percent
PCT.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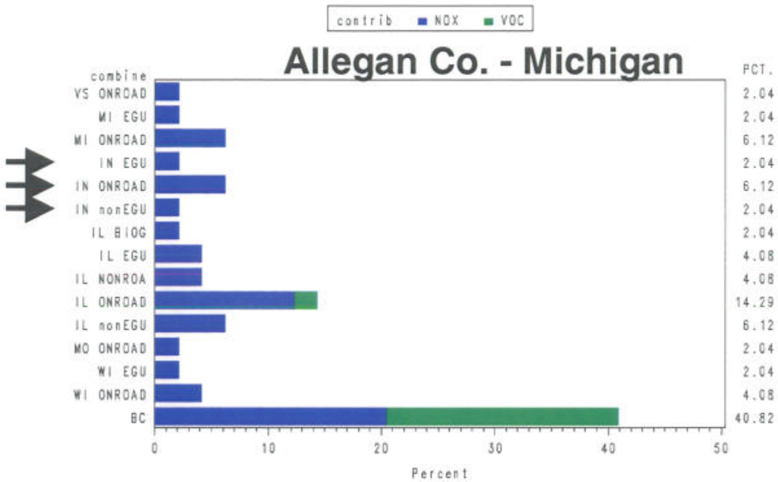
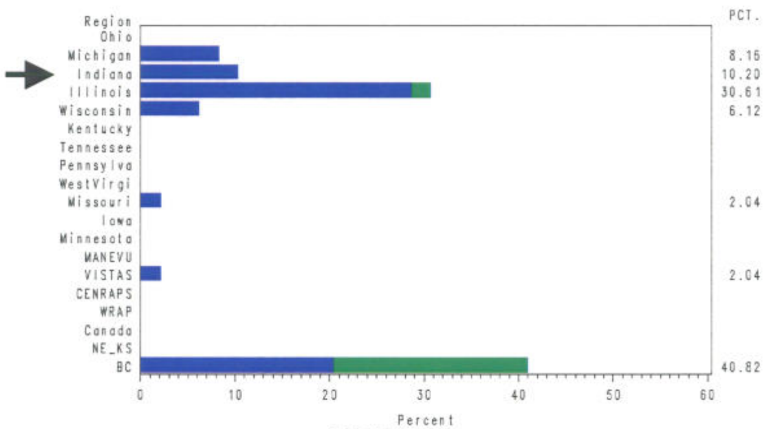
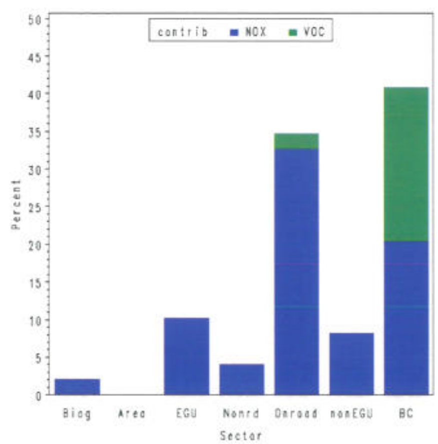
contrib NOX VOC
Percent
Sector
Biog Area EGU Nonrd Onroad nonEGU BC

2600500031







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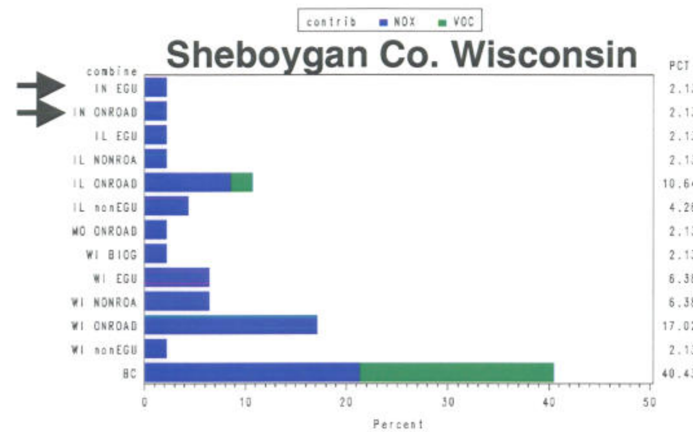

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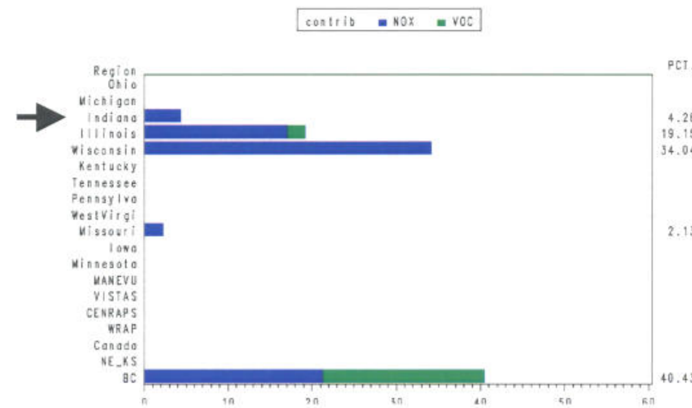

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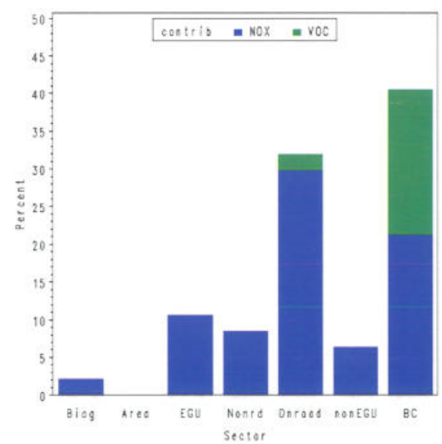
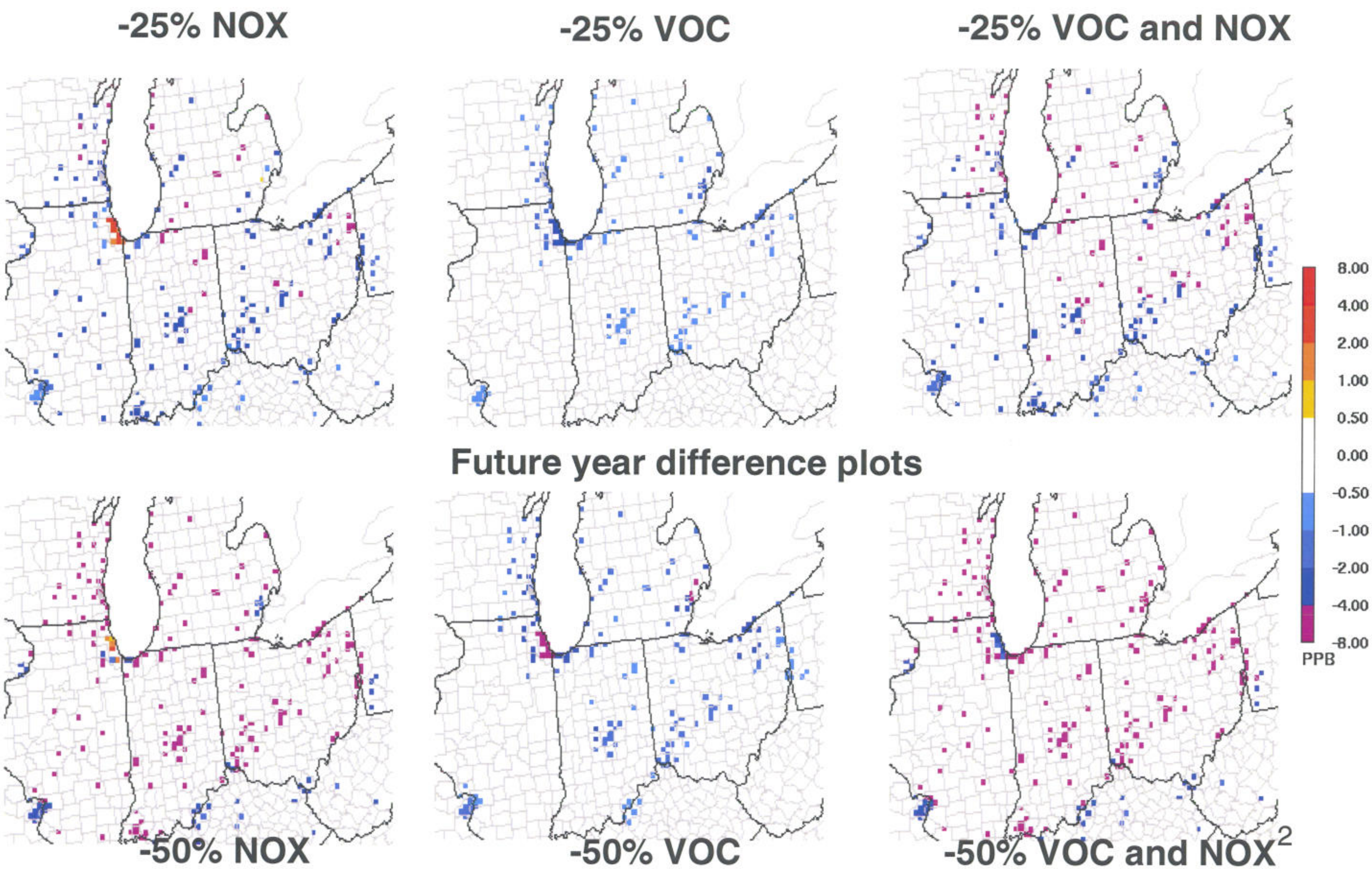


Round 2 Sensitivity Modeling Runs: VOC & NOx cuts after "on the books"/CAIR for Ozone

- **Future year sensitivity runs with NOx and VOC "across the board" emission reductions were made to emissions with CAIR emissions reductions already factored in.**
- **Emission reductions were modeled at 25% and 50% for NOx, VOC and both NOx and VOC.**
- **Results for Indiana:**
  - **25% NOx reduction yield 2 to 4 ppb ozone decrease in northern Indiana and 1 to 3 ppb ozone decrease in central and southern Indiana.**
  - **50% NOx reduction yield 8 to 10 ppb ozone decrease in northern Indiana and 7 to 8 ppb ozone decrease in central Indiana and 1 to 3 ppb ozone decrease in southern Indiana.**
  - **25% VOC reduction yield 0.3 to 1.5 ppb ozone decrease in northern Indiana and 0.1 to 0.75 ppb ozone decrease in central and southern Indiana.**
  - **50% VOC reduction yield 0.75 to 2 ppb ozone decrease in northern Indiana and 0.2 to 1.5 ppb ozone decrease in central and southern Indiana.**
  - **25% NOx and VOC reduction yield 3.5 to 5 ppb ozone decrease in northern Indiana and 2 to 4 ppb ozone decrease in central and southern Indiana.**
  - **50% NOx and VOC reduction yield 9 to 11 ppb ozone decrease in northern Indiana and 8 to 9 ppb ozone decrease in central Indiana and 4 to 6 ppb ozone decrease in southern Indiana**

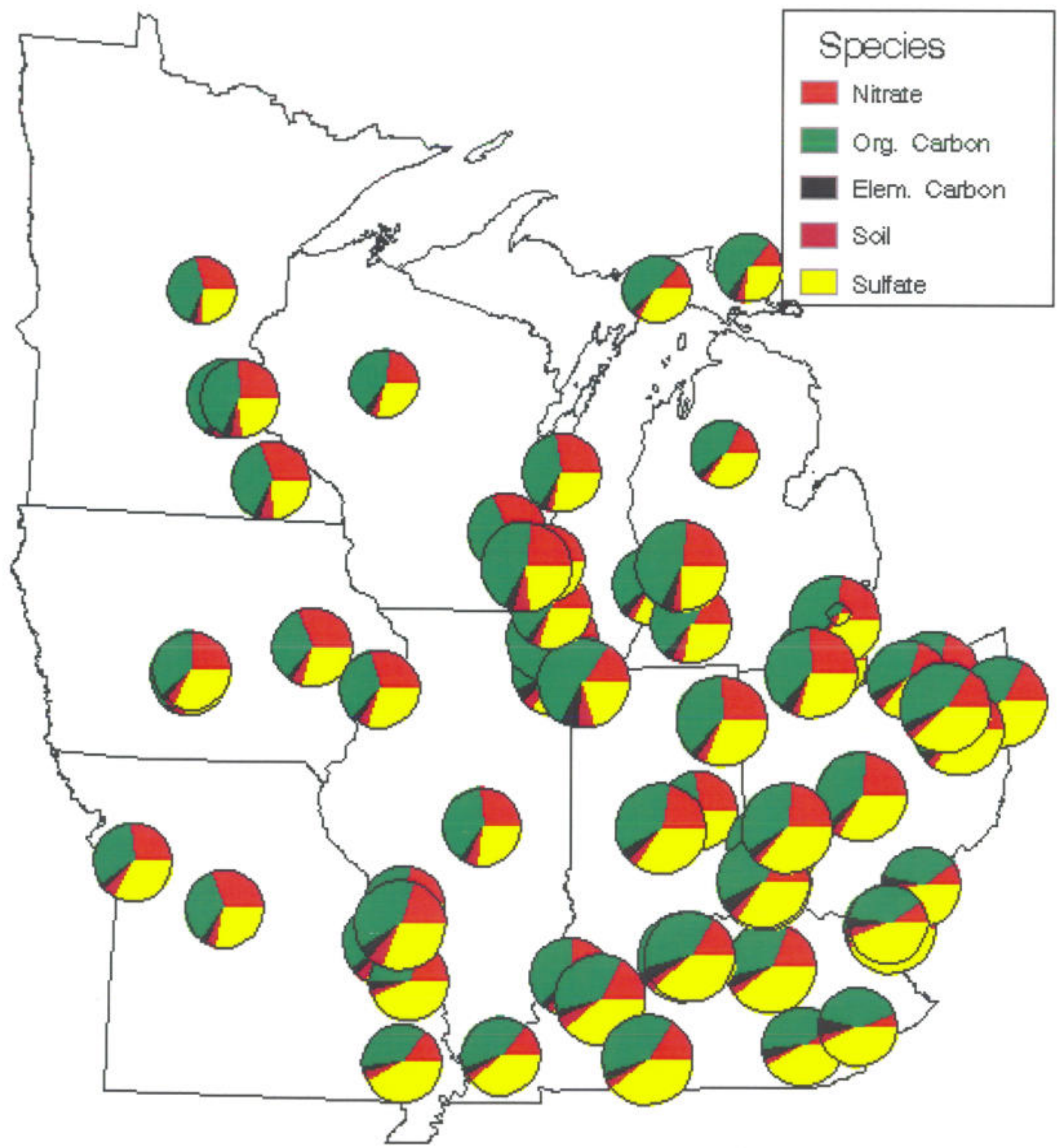
Model Response to VOC & NOX cuts after "on the books"/CAIR controls



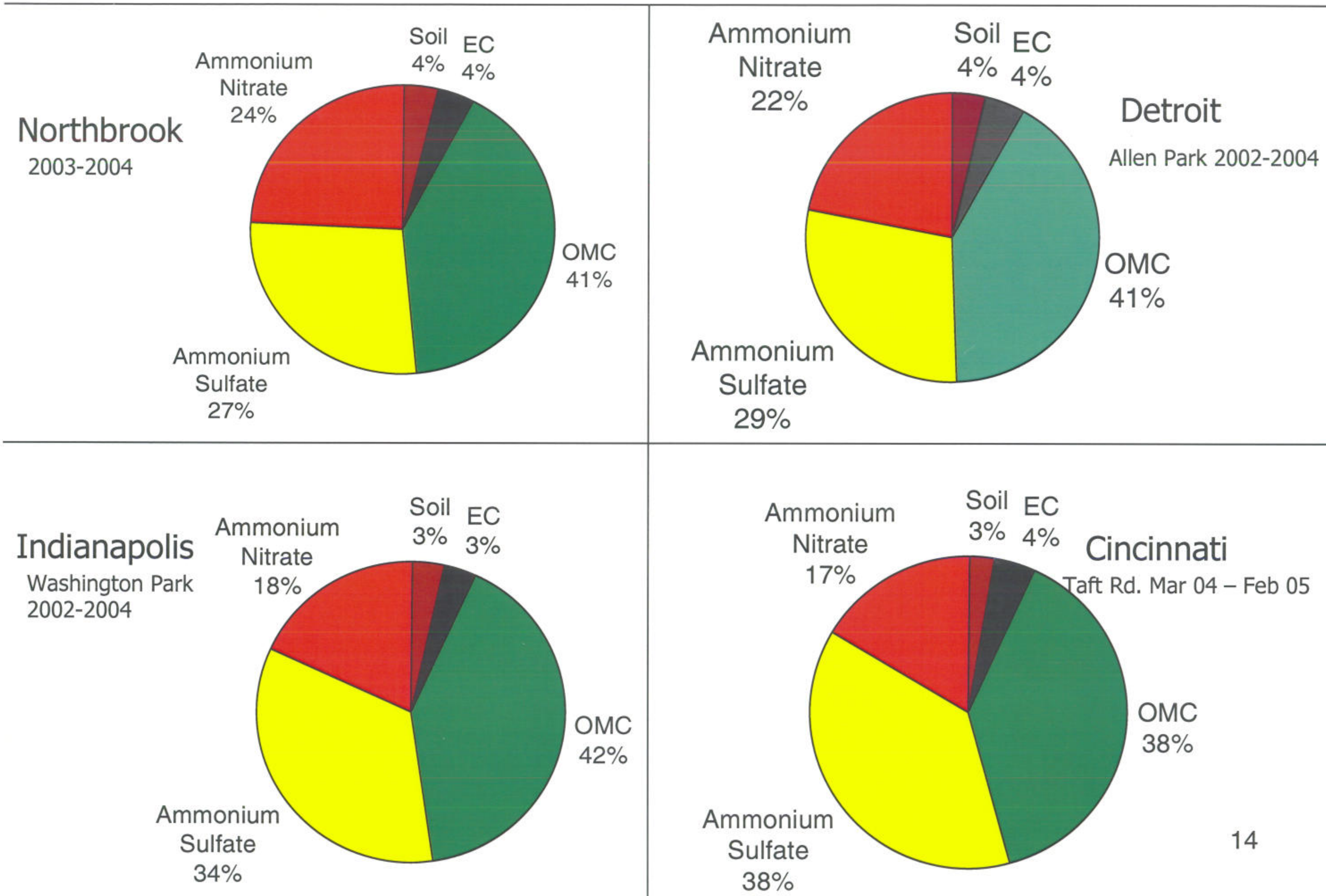
2

Annual Average Species Contribution to Fine Mass

Data from EPA Speciation Network, July 2002–June 2003



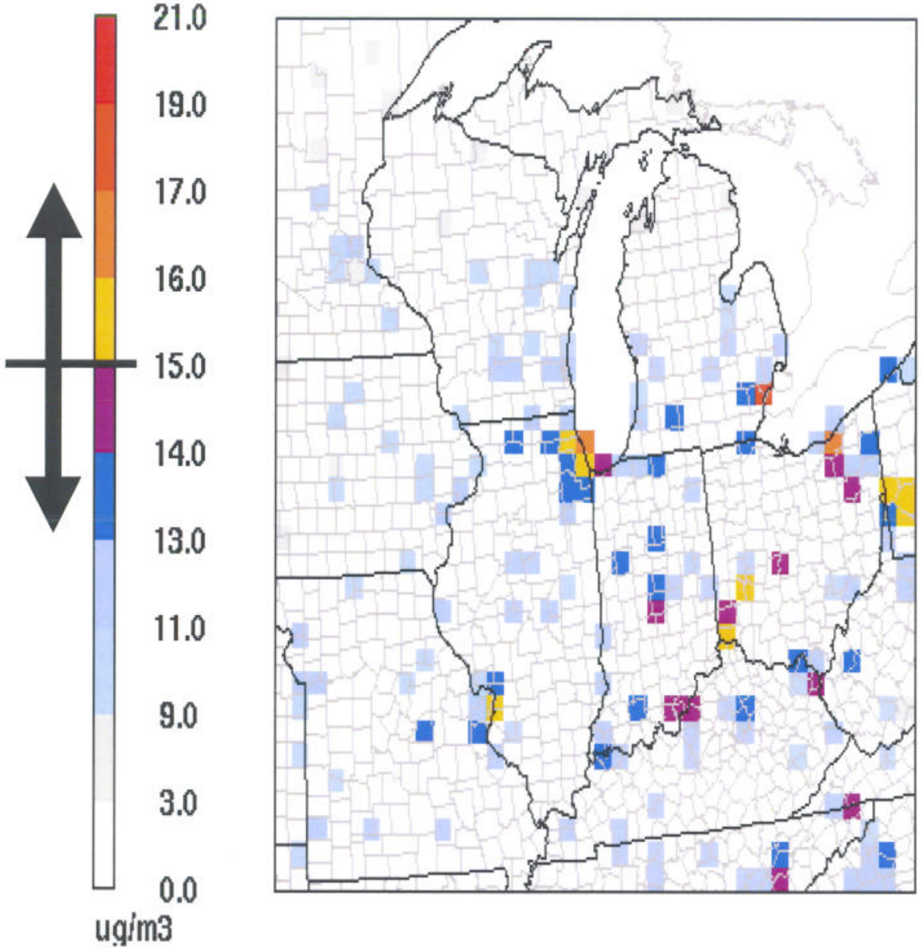
Average Composition of $PM_{2.5}$



Annual and 24 hour $PM_{2.5}$: Future Year Design Values for Evaluating a Revised $PM_{2.5}$ Annual and 24 hour $PM_{2.5}$ Standard

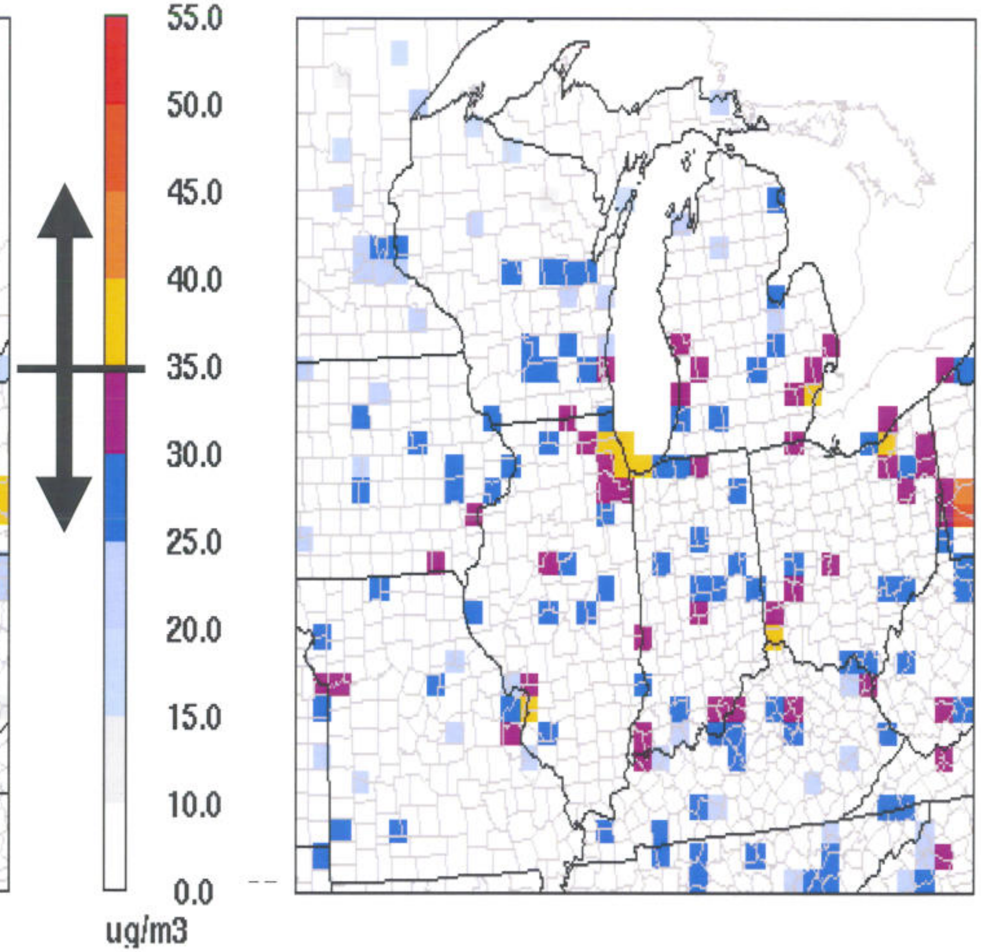
2009 R3S2

Annual PM2.5

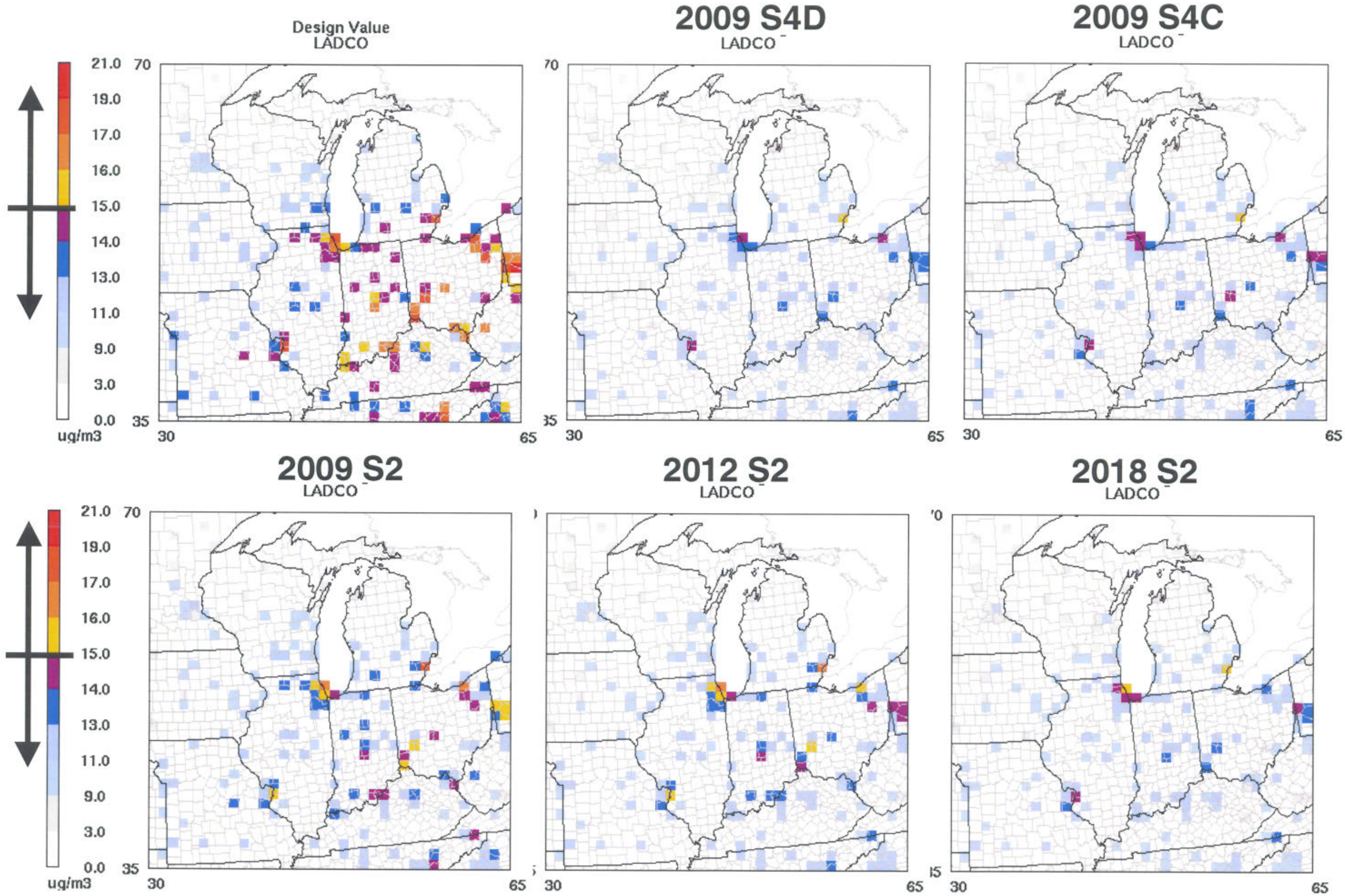


2009 R3S2

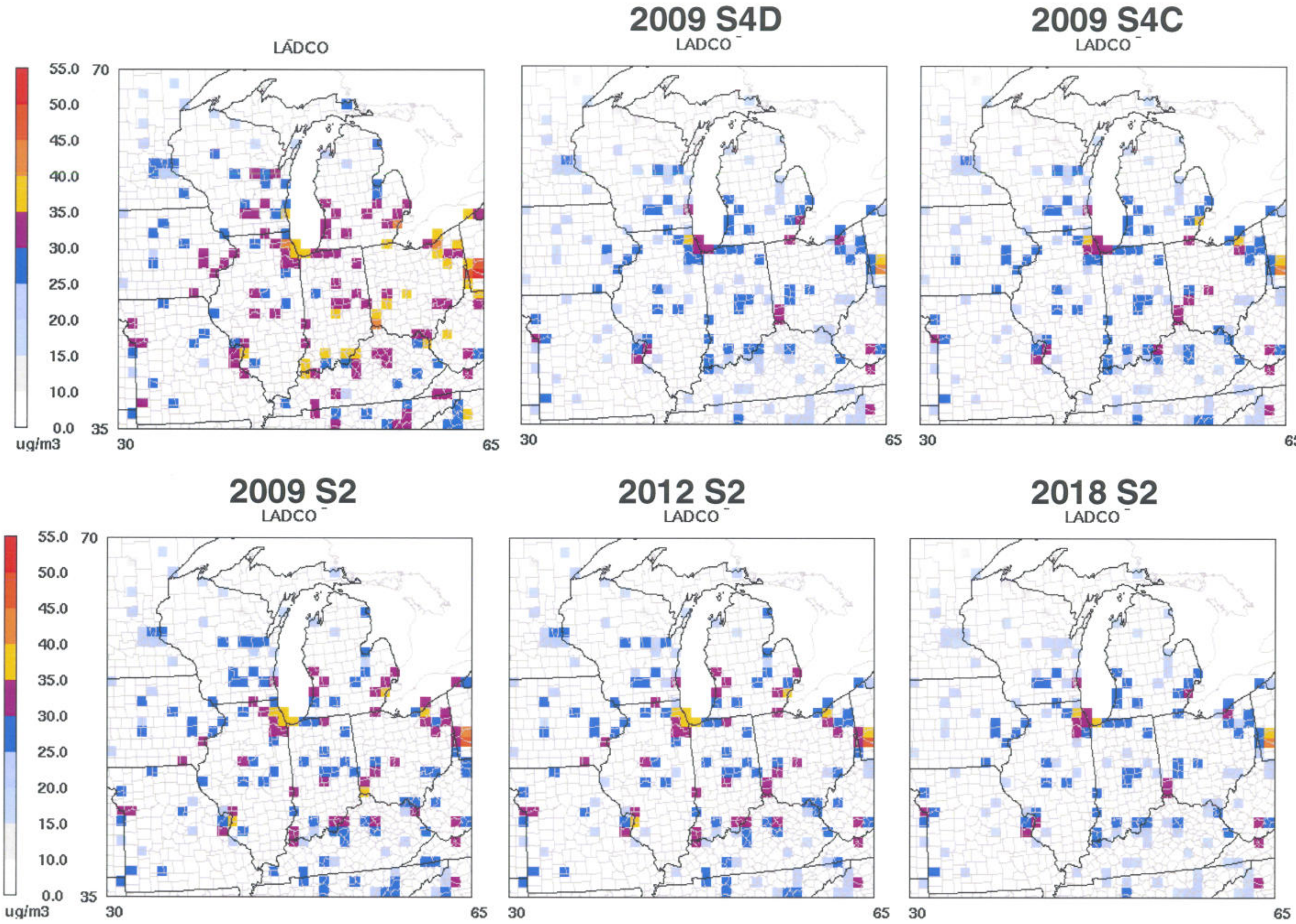
24-hour PM2.5



Annual PM2.5 - Future Year Design Values

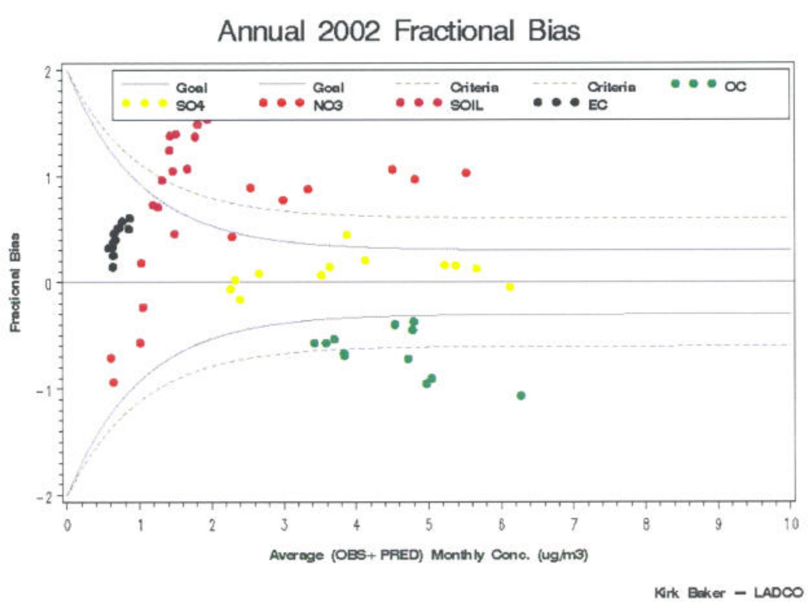


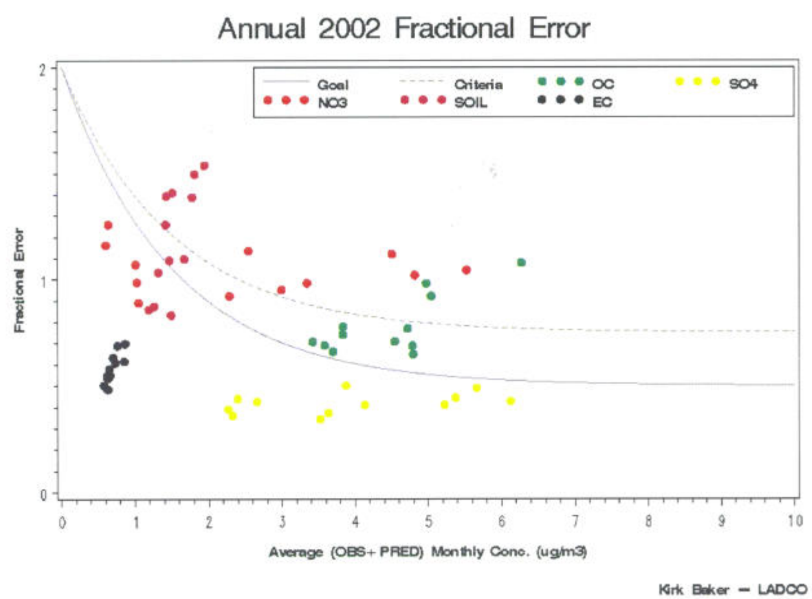
24-HR PM2.5 - Future Year Design Values



Model Performance Issues

- Ozone
  - Model performance for ozone is State Implementation Plan (SIP) quality and within U.S. EPA guidance of ±15% of mean normalized bias error and ±35% of mean normalized gross error.
- $PM_{2.5}$
  - Based on statistical analyses, current modeling under predicts organic carbon (year round) contributions to PM2.5 and over predicts nitrates (winter). OC and NO3 are outside the performance metrics for $PM_{2.5}$.
  - Current modeling shows over prediction of sulfates (summer) contributions to $PM_{2.5}$ but are within performance metrics for $PM_{2.5}$.
  - Statistical analysis metrics are consistent with U.S. EPA modeling guidance and includes analyzing bias, error, fractional bias and fractional error and include scatter plots, time series plots as well as daily/monthly bias and error comparisons and bell/trumpet graphs.





Upcoming Modeling Schedule

- Base K emissions should be ready by November of 2005.
  - Updates in Base K emissions will be:
    - Nonroad sources will have improved day specific emission estimates.
    - Point source and EGU will have improved temporal estimates.
    - Biogenic Secondary Organic Aerosols (SOA) will be added.
- Round 4 modeling will include the Base K emissions at 36 and 12 km.
  - Scheduled to be completed by mid December of 2005.
- Local controls for certain areas (central Indiana) will be modeled from the base and future year modeling conducted for Round 4.
  - Scheduled to be conducted in early 2006.

Final Report

Midwest Electric Rate Impact Study

BBC Research and Consulting

August 26, 2005

Final Report

August 26, 2005

Midwest Electric Rate Impact Study

Prepared for

Center for Energy and Economic Development;

Midwest Ozone Group; and

NiSource

Prepared by

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BBC RESEARCH & CONSULTING

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EXECUTIVE SUMMARY

Executive Summary

BBC Research & Consulting (BBC) was retained by the Center for Energy & Economic Development (CEED), the Midwest Ozone Group (MOG) and NiSource to examine the impacts of electric utility emission controls identified in the "LADCO EGU White Paper" on the Midwest economy. LADCO is considering two levels of utility emission reductions (EGU1 and EGU2) and two intermediate levels of control (IM1 and IM2). The proposed emission reductions under these controls are approximately 50 percent to 75 percent greater than the reductions required by EPA's 2005 Clean Air Interstate Rule (CAIR).

BBC studied the effects of additional emission controls in Illinois, Indiana, Michigan, Ohio and Wisconsin. Nine case study industries in those states were selected for study based on their intensive use of electricity. These industries included manufacturers of primary metals, transportation equipment, chemicals, food products, plastics and rubber, fabricated metals, paper, machinery and computers/electronic equipment. Coal mining was selected as the tenth case study industry because it is a major supplier to Midwestern electric generation.

BBC estimated the electric rate impacts of the proposed LADCO controls and the corresponding impact of higher electric rates on the case study industries and on household spending in the five states within the LADCO region. Rate impacts were estimated by comparing the projected annual electric utility revenue requirements, including costs of compliance with the LADCO controls, with projected annual electric utility revenue requirements after compliance with CAIR. BBC examined several scenarios of LADCO controls, including with and without replacement power to compensate for early generating unit retirements under EGU1 and EGU2.[1] BBC quantified overall effects on regional output and employment arising from the direct impacts on the case study industries and from the impacts of higher electric rates on household disposable income. Impacts were quantified using partial equilibrium analyses of each case study industry along with the IMPLAN economic input-output model.

The focus of the study was on the direct and secondary (or "multiplier") effects on the case study industries and on the portions of the economy supported by household spending. The findings here are conservative because impacts of higher electric rates on other industries and the commercial sector (which together account for about one-third of all electricity sales) were not included. Health and visibility-related economic benefits of emissions reductions and the potential short-term economic effects on the construction industry from building and installing pollution control equipment were also outside the scope of this study.

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[1] Annual costs of compliance, including both technology costs and replacement power to compensate for early retirement of older generating units, were provided by James Marchetti, Michael Hein and Edward Cichanowicz. Baseline electric utility revenues for 2012 and 2013 were projected by BBC based on current revenues, Energy Information Administration projections and EPA's Regulatory Impact Analysis of the CAIR Rule.

Key findings are as follows:

1. From a regional standpoint, electric rates in the year 2013 would be about 11 percent higher under EGU1 and nearly 16 percent higher under EGU2 than under the CAIR Rule. Electric rates would increase the most in Indiana (29% increase under EGU2) and the least in Michigan (12% increase under EGU2).
2. Demand for coal mined in Illinois, Indiana and Ohio is expected to decline by 48 percent under EGU1 and 54 percent under EGU2.
3. Economic output in the five-state region is projected to be reduced by $9.0 billion to $14.1 billion under EGU2 in 2013. Under EGU1, the reduction in annual state economic output is estimated to be between $6.9 billion and $10.4 billion.[2]
4. Employment in the five-state region is projected to be reduced by between 69,000 and 94,000 jobs under EGU2. Under EGU1, approximately 51,000 to 69,000 jobs would be lost.

Exhibit ES-1 summarizes the projected impacts on regional employment on a state-by-state basis.

Exhibit ES-1.
Projected job reductions under proposed LADCO EGU control measures

	2012		2013		
			Without Replacement Power	With Replacement Power	
	IM1	IM2	EGU1/EGU2	EGU1	EGU2
Illinois	1,020 – 1,370	4,660 – 6,350	9,300 –12,110	8,800 –11,410	13,400 – 17,610
Indiana	5,380 – 8,180	7,590 –11,730	17,680 –24,330	17,510 –24,150	22,280 – 31,140
Michigan	3,270 – 4,520	5,440 – 7,660	6,630 – 9,290	6,270 – 8,730	10,050 – 14,090
Ohio	5,510 – 7,800	5,960 – 8,600	16,410 –21,120	16,190 –20,780	18,300 – 23,660
Wisconsin	1,540 – 2,280	2,280 – 3,420	2,870 – 4,330	2,560 – 3,830	5,290 – 7,950
Total	***16,720 –24,140***	***25,930 –37,750***	***52,910 –71,200***	***51,340 –68,890***	***69,330 – 94,460***

Note: Totals may not add due to rounding.
Source: BBC Research & Consulting, 2005.

[2] Output and employment impact estimates include direct impacts on the case study industries, impacts on the suppliers and employees of those industries, and impacts on the economy due to reduced disposable income of residential consumers as a result of electric rate increases.

SECTION I.
Introduction

Introduction — Background

BBC Research & Consulting (BBC) was retained by the Center for Energy & Economic Development (CEED), the Midwest Ozone Group (MOG) and NiSource to examine the impacts of electric utility emission controls identified in the "LADCO EGU White Paper[1]" on the Midwest economy.

The Lake Michigan Air Directors Consortium (LADCO) was established in 1990 by the states of Illinois, Indiana, Michigan and Wisconsin. Ohio became a member of the consortium in 2004. LADCO's purpose is to provide technical assessments and assistance to its member states on regional air quality issues.

In January 2005, LADCO produced an "interim white paper" describing candidate control measures, beyond the mandatory controls already on the books, that might be considered by the LADCO states. LADCO is considering two levels of utility emission reductions — EGU1 and EGU2 — and two intermediate levels of control — IM1 and IM2. Allowable emission rates for electric generating units would be considerably lower under the LADCO strategies than under the EPA's 2005 Clean Air Interstate Rule (CAIR). For example, the regional budget for annual SO2 emissions would be reduced from about 1 million tons under CAIR to about 570,000 tons under IM2 and about 240,000 tons under EGU2.2 If enacted, the intermediate levels of control would be in force in 2012. EGU1 and EGU2 standards would begin in 2013.

BBC was asked to examine the impacts of the LADCO scenarios on electric rates in the LADCO states and the impacts of potential electric rate increases on electricity intensive industry, Midwestern households and the Midwestern economy. BBC's analysis includes CAIR in the baseline and only examines impacts beyond what will result from CAIR. BBC studied impacts on Illinois, Indiana, Michigan, Ohio and Wisconsin.

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[1] This is the popular name for a study by Mac Tec consulting group entitled "Interim White Paper–Midwest RPO Candidate Control Measures." The Midwest Regional Planning Organization is composed of and managed by LADCO, the Lake Michigan Air Directors Consortium.

[2] "Evaluation of the Midwest RPO Interim Measures and EGU1 and EGU2," Marchetti, Hein and Cichanowicz, June 28, 2005.

This analysis examines the EGU1 and EGU2 scenarios with and without the costs of "replacement power." These scenarios are expected to lead to early retirements of certain coal fired generating units and a corresponding reduction in regional generation capacity. The "with replacement power" scenarios consider the net additional cost of replacing the power that these units would have generated through additional use of existing natural gas-fired generation units, construction of new gas generating units and purchases of replacement power from outside the region.

Exhibit I-1 summarizes the control scenarios studied by BBC. The EGU1 and EGU2 scenarios with no purchases of replacement power yield similar results. Therefore BBC combined these two control scenarios into one in this analysis.

BBC's economic impact analysis is based on an assessment of the Midwest electric utility industry's response to the different control scenarios prepared by James Marchetti, Michael Hein and Edward Cichanowicz.[3]

Exhibit I-1.
Summary of LADCO pollution control scenarios examined in this study

Central Scenario	Year	Purchase of replacement power
IM1	2012	Not needed
IM2	2012	Not needed
EGU1/EGU2 without replacement power	2013	Excluded
EGU1 with replacement power	2013	Included
EGU2 with replacement power	2013	Included

[3] Ibid.

Midwest utilities would respond to the proposed control measures by investing in pollution control equipment, increasing their use of existing natural gas-fired generating units, building new gas units, switching from Midwest coal to low sulfur Wyoming coal ("fuel switching" in Exhibit I-2), and early retirement of Midwest generating units, which could lead to more power purchases from outside the region. Each of these responses will increase the cost of electricity for Midwest customers.

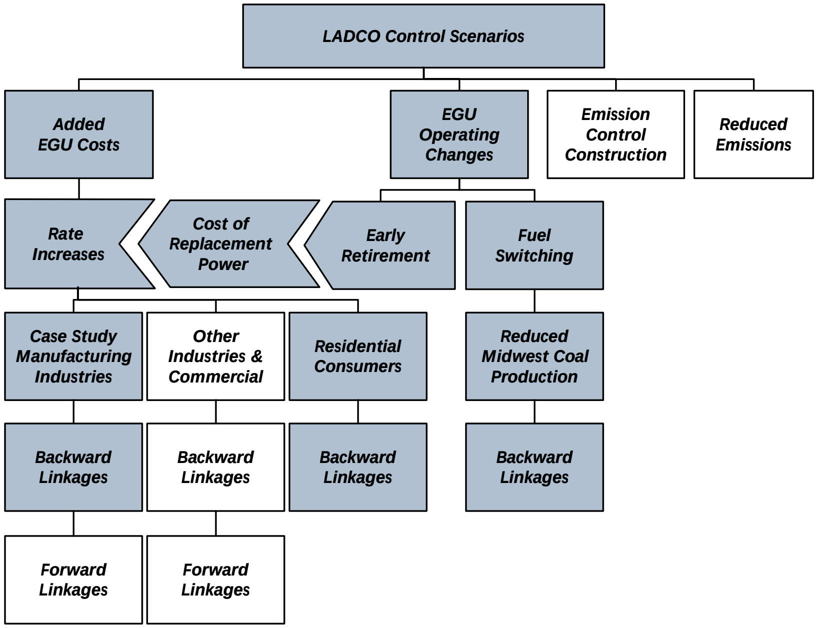
BBC's economic analysis begins with the projected annual cost impacts on the electricity industry. BBC then calculated rate impacts on Midwest electricity customers. These rate impacts are discussed in Section III of this report.

Because BBC could not conduct a comprehensive assessment of the rate impacts on all sectors of the Midwest economy, nine electricity-intensive industries and coal mining were selected as "case studies" for this analysis. Section II of this report introduces the case study industries.

The direct impact of increased electricity rates on case study industries is reduced output in each industry. As a result, each case study industry will reduce purchases from sectors providing key inputs. For example, cost increases for the transportation equipment industry will lead to reductions in demand for steel ("backward linkages" in Exhibit I-2). Job losses in these industries will also have a ripple effect through the Midwest economy. These effects are examined in Section V. BBC also modeled impacts on the Midwest coal industry from fuel switching.

Finally, residential electricity customers will spend more of their income on electricity and less on other items. BBC modeled these effects as well. Results are presented in Section V.

Exhibit I-2.
Factors included and not included in the economic study



Note: Shaded items were included in study; unshaded items were not.

It is also important to note the economic effects that BBC did not examine. Reduced air pollution in the Midwest may improve the health of local residents, enhance visibility and have other benefits. Each of these outcomes could have positive economic effects on the region. As shown in Exhibit I-2, effects of "reduced emissions" were not a part of BBC's study.

Because BBC analyzed long-term economic effects of the pollution control measures, short-term effects were not included. The short-term jobs created from installing the pollution control equipment required under the LADCO proposals were not estimated.

To be able to clearly examine the future economic conditions with and without the control scenarios, BBC assumed that residential customers would not change their use of electricity in response to higher prices. Without this assumption, power consumption in the Midwest would be lower, likely resulting in larger rate impacts, as the capital costs of pollution controls would be spread over a smaller volume of sales. Attempting to estimate the many iterations of these effects was beyond the scope of this study.

There are also several reasons why the analysis presented here could understate the negative economic effects of the pollution control strategies. Only nine case study industries, plus the coal industry, were examined when assessing direct effects of the pollution control measures. Increases in case study industry costs may lead to higher prices for their output — and correspondingly higher costs for other industries. BBC did not examine these effects ("forward linkages" in Exhibit I-2). Other reasons are noted in Exhibit I-3.

Exhibit I-3.
Reasons why the analysis may understate or overstate actual impacts

Reasons why analysis may understate actual impacts
Rate impacts limited to case study industries and households; one-third of electricity sales ignored
Did not analyze lost utility jobs due to early power plant retirements in Midwest or lost railroad jobs due to reduced coal transportation.
Forward linkages not included (e.g., effects of higher steel costs on rest of Midwest economy)

Reasons why analysis may overstate actual impacts
Did not analyze any health or visibility benefits
Did not analyze short-term employment created from installing pollution control equipment
Assumed no reductions in power use by residential customers due to higher rates

BBC modeled the economic impacts of the LADCO pollution control scenarios using the IMPLAN input-output model. This tool is widely used throughout the U.S. for regional economic impact analysis.

As much as possible, BBC relied on accepted state or federal data sources for the inputs to the IMPLAN model and other elements of the analysis. For example, inputs regarding industry responsiveness to cost increases ("elasticities," which are further discussed in Section IV of this report) primarily come from the U.S. Environmental Protection Agency Elasticity Databank. Current and projected average electricity revenues and rates come from the U.S. Energy Information Administration. Historic economic data were from federal sources such as the U.S. Census Bureau and the Bureau of Labor Statistics.

Each state in the region has developed projections of jobs by industry, which BBC used in developing the "baseline" (CAIR without additional LADCO controls) scenario.

Exhibit I-4.
Key data sources

Source	*Information*
Lake Michigan Air Directors Consortium (LADCO)	• EGU White Paper, prepared by MacTec, Inc. (www.ladco.org), Jan. 14, 2005.
James Marchetti, Michael Hein and Edward Cichanowicz	• Annual electric utility compliance costs and net costs of replacement power
Energy Information Administration (DOE)	• Current and projected electric rates, usage and utility revenues
EPA	• Rate increases associated with CAIR • Industry supply and demand elasticities
IMPLAN model and data files	• Electricity expenditures by industry and for residential users • Current output and employment by industry • Output and employment multipliers
State governments	• Projected baseline jobs by industry
Bureau of Labor Statistics	• Projected productivity changes by industry

Introduction — Terminology Definitions

Backward linkages — Economic relationship between an industry and its suppliers and employees. In economic impact analysis, incorporating backward linkages means capturing the effects of a direct change in a particular industry's output on the output of the industries that supply goods and services to that industry and to its employees.

Demand elasticity — The percentage decrease in the quantity of a good or service that customers will purchase given a one percent increase in the price of that good or service.

Disposable income — Household income after payment of taxes.

EGU — Electric generating units. Note that one powerplant may be comprised of several individual coal or natural gas-fired generating units.

Energy intensity — The cost of purchases of electricity by an industry relative to the total value of the industry's output.

Forward linkages — Economic relationships between an industry and its customers. In economic impact analysis, incorporating forward linkages means capturing the effects of price changes in a particular industry's output on the costs and/or output of the industries that purchase goods or services from it.

IMPLAN input-output model — a PC based regional economic modeling system originally developed by the US Forest Service and currently maintained by Minnesota IMPLAN Group. Widely used for economic impact studies.

Jobs — In this study, jobs are as defined in the IMPLAN data sets and include both full and part-time employment as well as self-employed proprietors.

Labor income — In this study, labor income is as defined in the IMPLAN data sets and includes wage and salary income of employees and earnings of proprietors.

NAICS — North American Industry Classification System. Official definitions and numeric codes for industries as published by the Office of Management and Budget in 1997. Replaced the previous Standard Industrial Classification (SIC) system.

Output – The value of production by an industry.

Partial equilibrium analysis — A simplified form of economic analysis that focuses on identifying changes in supply, demand and prices in on one market (e.g. the market for steel) at a time.

Supply elasticity — The percentage increase in the quantity of a good or service that suppliers will produce given a one percent increase in the price of that good or service.

SECTION II.
Case Study Industries

Case Study Industries — Selection

To select the case study industries for these analyses, BBC examined total employment in the industry in the Midwest, the industry's total electricity purchases, and electricity purchases as a share of total output (e.g., an industry's electricity-intensity). BBC examined industries at the three-digit NAICS code level of detail.

Based on these criteria, nine sectors were selected for the industry case studies. For example, the food products industry, which includes meat processing, dairy, bakeries and other food processing sectors, is a large employer in the Midwest with about $0.8 billion in electricity purchases in 2002. Electricity expenditures totaled about 0.9 percent of the cost of producing food products. (Self-generated power was not included in the analysis of electricity purchases.)

The largest electricity purchaser in the Midwest is the primary metals manufacturing industry (steel, aluminum and other primary metals). BBC estimates that the Midwest's primary metals industry purchased $1.2 billion of electricity in 2002, more than 2 percent of the industry's total production expenditures.

Three other case study industries in the Midwest — paper manufacturing, chemicals manufacturing and plastics and rubber manufacturing — had electricity expenditures that exceeded 1 percent of these industries' total outlays. Transportation equipment manufacturing, which includes auto and truck manufacturing, spent more than $1 billion on electricity purchases in the region. BBC also examined computer and electronic product manufacturing, fabricated metal production and machinery manufacturing. Because of possible impacts on demand for local coal, the Midwest coal mining industry was also analyzed.

Exhibit II-1.
Electricity purchases by Midwest case study industries, 2002

Case Study Industry	*Value of Electricity Purchased (Millions)*	*Percent of Total Outlay*
Food Products	$848	0.89%
Paper Manufacturing	$680	1.90%
Chemical Manufacturing	$1,034	1.13%
Plastics & Rubber Production	$830	1.63%
Computer & Electronic Product Manufacturing	$170	0.52%
Primary Metal Manufacturing	$1,212	2.34%
Fabricated Metal Production	$713	0.98%
Machinery Manufacturing	$451	0.56%
Transportation Equipment	$1,093	0.41%
Coal Mining	$36	1.48%
Total Case Study Industries	***$7,065***	
Total Industrial and Commercial	***$20,569***	

Source: IMPLAN.

Case Study Industries — 2002 Employment

Exhibit II-2 illustrates total employment in 2002 in the 10 case study industries in each Midwest state.

Case study industry employment in Ohio totaled 637,000 employees in 2002, highest among the Midwest states. Transportation equipment, fabricated metals, plastics and rubber manufacturing and machinery manufacturing were large employers in this state. Compared with other states, Ohio also has a relatively large coal mining sector (3,500 employees in 2002).

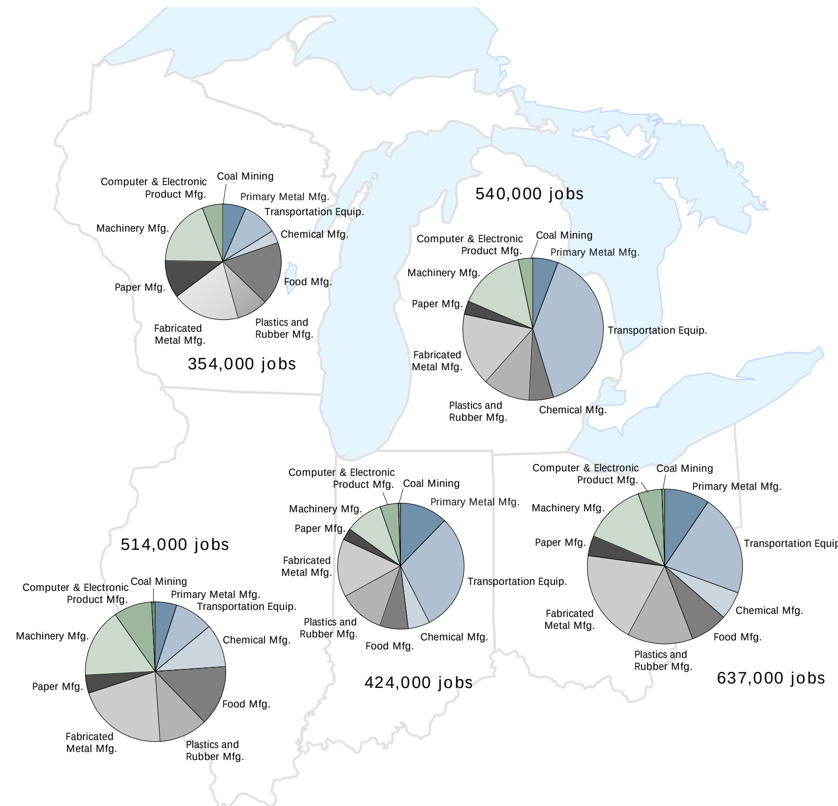
In Michigan, there were 540,000 jobs in the case study industries in 2002. The transportation equipment sector accounted for 40 percent of these jobs.

Illinois had nearly as many jobs in the case study industries as Michigan — 514,000 in 2002. The largest case study sector in Illinois, fabricated metal manufacturing, accounted for 114,000 of these jobs. Illinois had the largest chemical manufacturing and computer and electronic products industries among the Midwest states. There were 3,800 coal mining jobs in Illinois in 2002.

Case study industries accounted for 424,000 jobs in Indiana in 2002. About 128,000 of these jobs were in the transportation equipment sector. Fabricated metals and primary metals manufacturing were also large employers. Indiana had 2,200 coal mining jobs in 2002.

In 2002, Wisconsin had 354,000 jobs in case study sectors. Machinery, fabricated metal, food and paper manufacturing were large employers.

Exhibit II-2.
Employment in case study industries in 2002



Source: U.S. Census Bureau, EPCD, County Business Patterns.

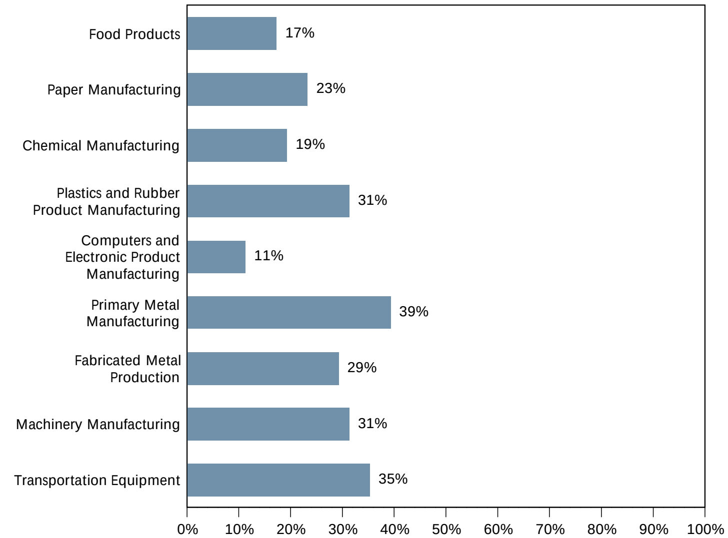
Case Study Industries — Competitiveness in U.S.

As a whole, the case study industries are highly competitive. In many of these industries, manufacturing plants in the Midwest compete against manufacturers throughout the U.S. and in other countries.

As shown in Exhibit II-3, 39 percent of U.S. primary metals employment is located in the five-state region based on 2002 County Business Patterns data. About one-third of the U.S. transportation equipment manufacturing, machinery manufacturing and plastics and rubber manufacturing is located in the Midwest. Much of the output from these industries is sold in other states or goes into other products that compete nationally and internationally. (The Midwest accounts for only 16 percent of the U.S. population.)

The only case study industry in which the Midwest has a comparatively small share of U.S. employment (apart from coal mining) is computers and electronic product manufacturing (11 percent of U.S. employment.)

Exhibit II-3.
Midwest share of U.S. employment, 2002



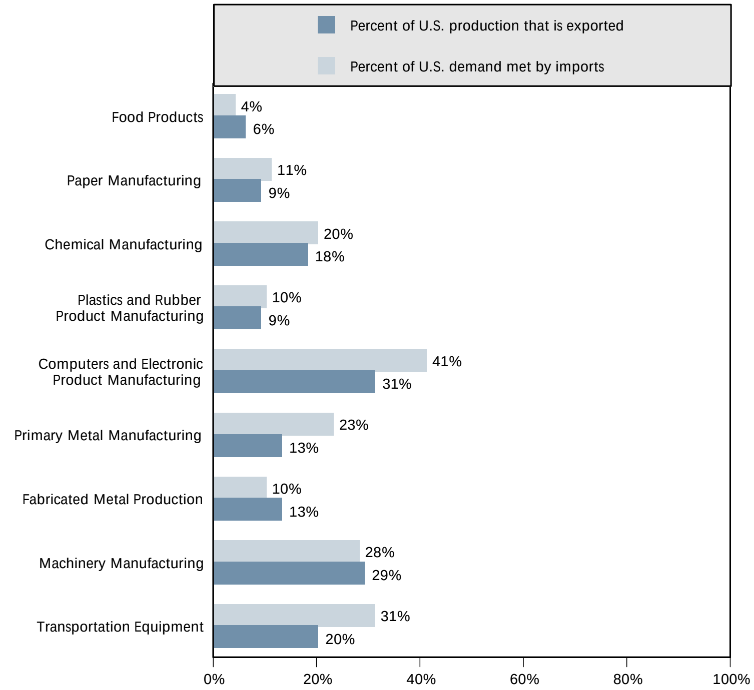
Source: U.S. Census Bureau, EPCD County Business Patterns

Although reliable data are not available for imports to the U.S. and exports from the U.S. on a regional basis, national statistics provide insight into the international competitiveness of the case study industries.

About 40 percent of the U.S. demand for computers and electronic products is met by imports. Almost one-third of U.S. demand for transportation equipment is fulfilled by imports. Imports of machinery, primary metals and chemicals are also relatively high.

Similarly, a large proportion of U.S. production of computers and electronic products, machinery and transportation equipment is exported to other countries. Even in industries such as chemicals, primary metals and fabricated metals, foreign competition is a major force in the U.S. marketplace. Only food products manufacturing is relatively insulated from foreign competition.

Exhibit II-4.
U.S. imports and exports for case study industry output, 2001



Source: International Trade Administration, 2005.

The coal mining industry is a special case among the industries examined in this study. With about 9,000 workers, coal mining does not employ as many people in the Midwest as the manufacturing industries studied. The industry could face, however, major impacts from the LADCO control measures.

Dun & Bradstreet data show 18 coal mining establishments in the Midwest with over 100 employees. Seven of the large coal mining establishments are located in Illinois, six are in Indiana and five are in Ohio. Almost all of the coal mining in the Midwest is used for generating power, and most of the Midwest coal that is mined stays in the Midwest.

Exhibit II-5.
Coal mining establishments with 100+ employees

Source: Dun & Bradstreet Marketplace.

SECTION III.
Midwest Electricity Rates

BBC received estimates of the direct costs to Midwest utilities from the proposed LADCO-EGU control measures from Manchetti, Hein and Cichanowicz. The cost impacts were for two versions of intermediate implementation scenarios — IM1 and IM2 — and two full implementation control scenarios — EGU1 and EGU2. The Marchetti group examined the EGU1 and EGU2 scenarios with and without replacement power for the early retirement of generation under these scenarios. The "without replacement power" cost impacts were so similar under EGU1 and EGU2 that BBC combined these two scenarios.

As shown in Exhibit III-1, annual control costs vary from $2.0 to $3.2 billion in 2012 in IM1 and IM2.

For EGU1 and EGU2, annual control costs are $5.0 billion and $7.1 billion per year, respectively, assuming that utilities in the region would purchase power to replace the units that would need to be retired. These annual compliance cost figures are for 2013. Without this replacement power assumption, EGU1 and EGU2 would have costs of about $5.2 billion in 2013.

All cost estimates are in 2003 dollars.

Exhibit III-1.
Projected annual direct costs of proposed LADCO EGU control measures (millions of 2003 dollars)

	2012		2013		
			Without Replacement Power	With Replacement Power	
State	IM1	IM2	EGU1/EGU2	EGU1	EGU2
Illinois	$142	$646	$1,118	$1,048	$1,660
Indiana	$622	$873	$1,496	$1,488	$1,949
Michigan	$353	$584	$740	$696	$1,112
Ohio	$713	$773	$1,447	$1,418	$1,640
Wisconsin	$204	$303	$393	$345	$711
Region	***$2,035***	***$3,179***	***$5,194***	***$4,995***	***$7,073***

Note: Totals may not add due to rounding.
Source: James Marchetti, Michael Hein and J. Edward Cichanowicz, 2005.

To determine impacts on electricity rates, BBC compared the annual cost of compliance with the baseline revenues projected for each state for 2012 and 2013, summarized in Exhibit III-2. Historic figures by state came from the Energy Information Administration. State electricity revenue projections were determined by applying regional growth in revenues from EIA forecasts to each state, using 2003 revenues as the base year. The growth in revenues for Michigan, Ohio and Indiana was based on EIA forecasts for the ECAR region. The larger relative increase for Illinois and Wisconsin is based on the EIA forecasts for the MAIN region.

As shown in Exhibit III-2, electricity retail sales revenues for the five-state region were projected to be about $40 billion in 2005 (in 2003 dollars). By 2013, total electricity sales revenues were expected to grow to $45 billion (in 2003 dollars). These projections include additional costs from compliance with CAIR, estimated by EPA to be a 2.3 percent rate impact for the country as a whole.

Exhibit III-2
Annual revenues from retail sales of electricity, with CAIR for 2012 and 2013 (millions of 2003 dollars)

State	2005	2012	2013
Illinois	$9,650	$10,771	$11,067
Indiana	6,073	6,432	6,723
Michigan	8,361	8,856	9,256
Ohio	11,157	12,262	12,816
Wisconsin	4,418	4,931	5,066
Region	***$40,080***	***$43,252***	***$44,928***

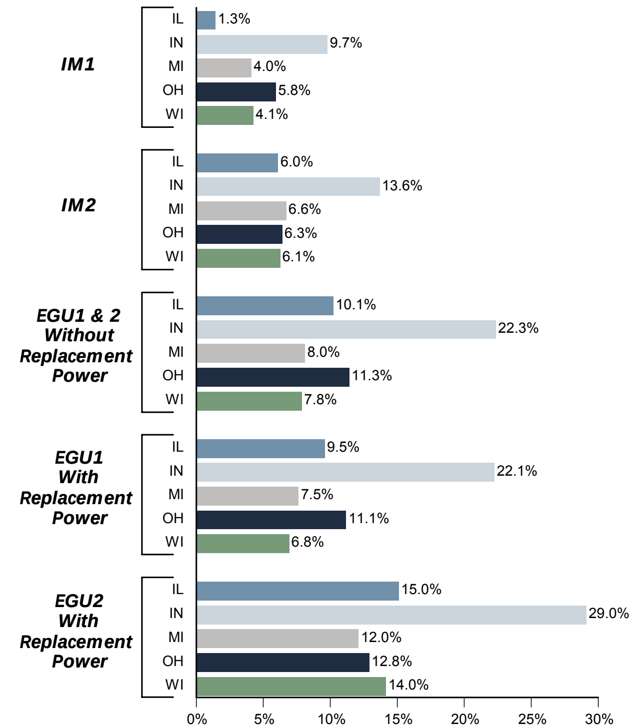
Note: CAIR rate impacts estimated by EPA to be 2.3 percent nationally.
Source: BBC Research and Consulting from U.S. Department of Energy, Energy Information Administration.

BBC projected impacts of LADCO control measures on electricity rates by dividing the total annual control costs in a state by the projected electricity revenues for that state without LADCO measures (but with CAIR). For example, the 1.3 percent impact on rates in Illinois in 2012 from IM1 was calculated based on the $142 million in compliance costs (2003 dollars) divided by the $10,771 million in electricity sales revenues for Illinois in the baseline scenario.

Rate impacts are the smallest (1 to 10 percent increases in rates) for IM1 and the highest for the EGU2 with replacement power control scenario. In states where utility revenue requirements are expected to be relatively low in 2012 and 2013, such as Indiana, the percentage impact on rates is highest. For example, electricity rates in Indiana are projected to increase by 9.7 percent in 2012 under IM1 and by 29.0 percent in 2013 under EGU2 with replacement power. EGU2 with replacement power would increase rates in other states by 12 to 15 percent.

Rate impacts of IM1 would be the smallest on a percentage basis in Illinois, where rates might need to increase by only 1 percent in 2012. The required percentage increase in electricity rates would be smallest in Wisconsin for EGU1 and EGU2 except for the EGU2 with replacement power scenario. Rate impacts for EGU2 with replacement power would be the smallest in Michigan.

Exhibit III-3.
Impacts of proposed LADCO EGU control measures on 2012 and 2013 electricity rates — percent change*



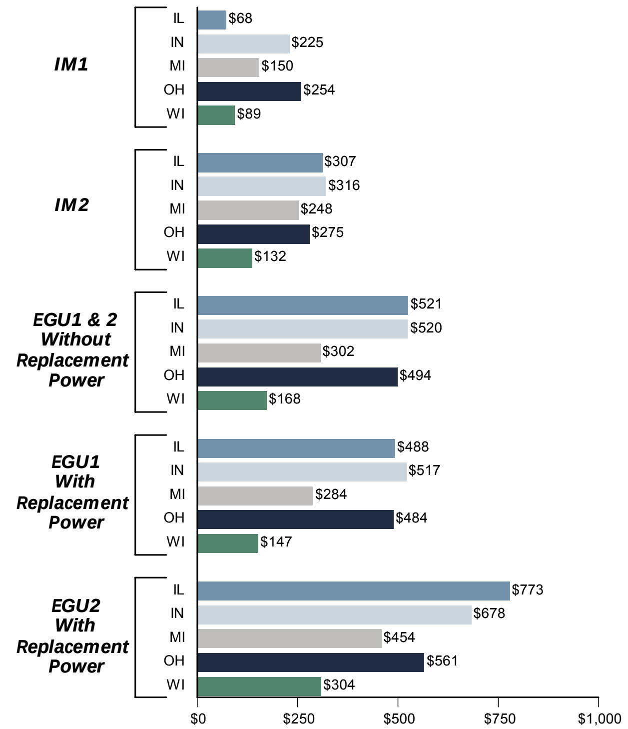
* Rate increases over and above increases needed to comply with CAIR Rule. IM1 and IM2 scenarios examined in 2012, EGU1 and EGU2 scenarios in 2013.

Source: BBC Research & Consulting.

BBC assumed that the percentage impacts on electricity rates from LADCO control measures would be the same across all customer classes. For example, if EGU2 with purchase of replacement power would raise rates by 29 percent in Indiana in 2013 compared with baseline rates for that year, each rate class was assumed to face 29 percent higher electricity rates. With this rate increase, households in Indiana would pay $678 million more for electricity in 2013 under EGU2 (with replacement power) than under the baseline.

BBC determined the increased expenditures for households based on expenditure data, by household income group, in IMPLAN.

Exhibit III-4.
Additional annual electricity costs for residential customers under proposed LADCO EGU control measures* (millions of 2003 dollars)



* IM1 and IM2 scenarios examined in 2012, EGU1 and EGU2 scenarios in 2013.

Source: BBC Research & Consulting.

Midwest Electricity Rates — Relative Affordability

One way to gauge the impact of the rate increases on the Midwest's economic competitiveness is to compare Midwest electricity rates to other states in the U.S. today and what they would be in the future with the LADCO control measures.

In 2003, electricity rates in Illinois, Michigan, Ohio and Wisconsin were about average for the U.S. Ranking each state from 1 (lowest average rates) to 50 (highest average rates), Wisconsin would place 24th lowest and Michigan would be 31st lowest, with Ohio and Illinois ranking 27th and 29th lowest, respectively. Rates in Indiana are currently low relative to other parts of the country. Only four states in 2003 had average electricity rates lower than Indiana.

With EGU1 (with replacement of power from early retirement of Midwest generating units), Indiana would go from an inexpensive state for electricity rates to one ranking 24th lowest among the 50 states. Each of the other states except Wisconsin would be in the group of the 20 most expensive states for electricity costs.

Impacts on relative competitiveness of electricity rates are larger under EGU2 (with replacement of power). For example, Illinois would now have higher average rates than 37 of the 50 states. After being a very low-rate state, Indiana would move into the group of "high rate" states.

These rate increases could affect the competitiveness of existing employers in the region when competing nationally and internationally, and potentially make the Midwest a less-attractive location for expansion and location of new firms.

Exhibit III-5.
Effect of projected rate increases on affordability of industrial electric rates – EGU1

	Affordability Ranking Among 50 States	
State	***Current (2003)***	***With Projected EGU1 Rate Increase (2013)***
Illinois	29	34
Indiana	5	24
Michigan	31	33
Ohio	27	32
Wisconsin	24	28

Note: 1 = state with lowest rates and 50 = state with highest rates.
Source: BBC Research and Consulting from U.S. Department of Energy, Energy Information Administration.

Exhibit III-6.
Effect of projected rate increases on affordability of industrial electric rates – EGU2

	Affordability Ranking Among 50 States	
State	***Current (2003)***	***With Projected EGU2 Rate Increase (2013)***
Illinois	29	38
Indiana	5	27
Michigan	31	35
Ohio	27	33
Wisconsin	24	32

Note: 1 = state with lowest rates and 50 = state with highest rates.
Source: BBC Research and Consulting from U.S. Department of Energy, Energy Information Administration.

SECTION IV.
Impacts on Case Study Industries

Impacts on Case Study Industries — Approach

Modeling impacts of higher electricity rates on case study industries is complex. This section of the report begins by describing BBC's approach.

The direct impact of higher production costs for industries is lower output. The magnitude of the change in output depends on whether the firms facing higher costs have any ability to pass along these cost increases to purchasers of their products.

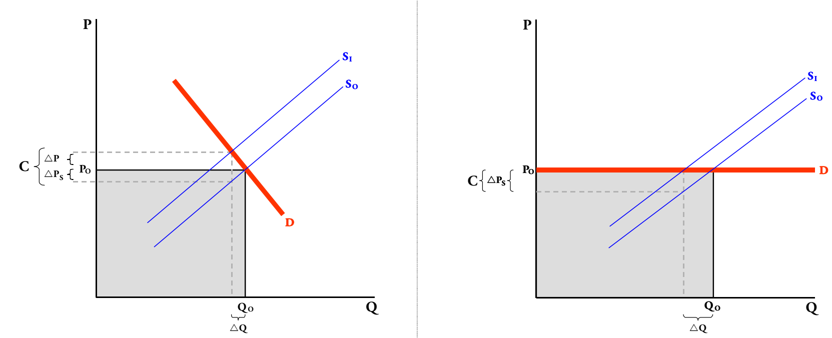
In the left hand graph in Exhibit IV-1, BBC assumes that producers have enough market power that customers will still purchase output from those producers even at higher prices. In other words, firms facing cost increases for their inputs can pass along some of those higher costs to their customers. The increases in firms' cost of production cause the supply curve to shift upward as it now costs more to produce any given level of output. Because of the higher prices, customers for the output decrease the quantity they purchase.

This view of the response to a cost increase is most accurate for cases in which all or most producers in a market face increases in the cost of an input. Rising global oil prices and national environmental regulations are examples of increased costs of production that can be fully or partially passed on to purchasers of a product, whether it be gasoline or plastics. However, the proposed LADCO control measures would only affect industries that purchase power produced in the Midwest. Therefore, a manufacturing plant facing higher electricity costs in Indiana would be at a disadvantage when competing with a plant located in areas where there are no similar cost increases.

At an extreme, the graph to the right in Exhibit IV-1 illustrates how a cost increase specific to only some firms could affect those firms. If there are many other firms competing in this industry that do not face the same cost increases, the firm examined in the graph would not be able to pass higher costs along to the purchasers of its product. If the firm tried to do this, customers would simply go to other sources of this good. In the economists view, the firm is a "price taker" facing a perfectly elastic demand for its product. The supply curve for the firm shifts upward, just as in the previous example, but the market does not absorb any of the additional cost. The firm must reduce its output to the point where it can make and sell its product for the same price it was getting before.

Exhibit IV-1.
How regional industries respond
to cost increases depends on market power

If costs increased across the U.S.... ***If only one firm experienced cost increase...***



...some added costs passed forward. ***...all costs must be absorbed by firm.***

Source: BBC Research & Consulting.

Impacts on Case Study Industries — Approach

The slopes of the supply curves in Exhibit IV-1 reflect how much a firm's, or an industry's, costs increase as it increases production. This relationship is known as the elasticity of supply. In this study, BBC attempted to analyze long-run supply elasticities where firms can make changes in their plant and their production processes and are not limited to just hiring more or fewer employees or changing their orders for materials.

A supply elasticity of 1.0 means that for every 1 percent increase in price, the firm can increase output by 1 percent. A supply elasticity of less than 1.0 means that a firm or industry would increase output by less than 1 percent given a 1 percent increase in price. Supply elasticities greater than 1.0 mean that firms will have larger increases in output for a given price increase.

BBC developed supply elasticities from the U.S. Environmental Protection Agency's Elasticity Database. The EPA has gathered elasticity estimates related to the paper, chemicals and primary metals industries (as well as other manufacturing industries outside of the case study group). For other industries examined in this report, BBC relied on the average of EPA supply elasticities across all manufacturing sectors. Exhibit IV-2 shows these elasticities.

Exhibit IV-2.
Supply elasticities for case study industries

Case Study Industry	*Supply Elasticity*	*Source*
Food Products	2.86	EPA average of all manufacturing industries
Paper Manufacturing	0.80	EPA estimates
Chemical Manufacturing	4.01	EPA estimates
Plastics & Rubber Production	2.86	Average of all manufacturing industries
Computer & Electronic Product Manufacturing	2.86	Average of all manufacturing industries
Primary Metal Manufacturing	1.44	EPA estimates
Fabricated Metal Production	2.86	Average of all manufacturing industries
Machinery Manufacturing	2.86	Average of all manufacturing industries
Transportation Equipment	2.86	Average of all manufacturing industries

Source: Complied by BBC Research and Consulting from U.S. Environmental Protection Agency Elasticity Databank, 2005.

Impacts on Case Study Industries — Approach

The slopes of the demand curves illustrated in Exhibit IV-1 show the degree to which purchasers of products will absorb firms' cost increases or just cut back on the amount of output they will purchase. This responsiveness is known as the elasticity of demand for a product. A demand elasticity of -1.0, for example, means that customers will decrease their purchases of a product by 1 percent given a 1 percent increase in price. (As with the supply elasticities, BBC sought to model long-term elasticity of demand for these industries.)

BBC examined effects of the electricity cost increases using two sets of assumptions about demand elasticities for case study industries to capture the range of potential industry responses to cost increases.

The first set of assumptions follows the logic of the left hand graph in Exhibit IV-1 — Midwest industries could pass along some of the cost increases to purchasers of their products. BBC used elasticity estimates from EPA reports, as shown in Exhibit IV-3. For computers and electronic products, BBC used elasticities determined through a literature review. The elasticities are generally for the U.S. economy as a whole, so they probably overstate the degree to which customers are willing to accept price increases from firms from a single region of the country. Demand for Midwest output is likely more price elastic than demand for U.S. output as a whole, so regional price increases would be more difficult to pass on to customers.

BBC also examined impacts on the case study industries assuming that all firms in the Midwest were price takers. Demand was assumed to be perfectly elastic; that is, all purchasers would shift to other sources of supply if the Midwest firms tried to raise their prices.

The two sets of demand elasticity assumptions represent two extremes of possible market response. Therefore, BBC presents the case study industry impact estimates as a range.

Exhibit IV-3.
Demand elasticities for case study industries

Case Study Industry	Demand Elasticity	Source
Food Products	-0.41	EPA estimates
Paper Manufacturing	-1.14	EPA estimates
Chemical Manufacturing	-1.75	EPA estimates
Plastics & Rubber Production	-1.37	Average of all manufacturing industries
Computer & Electronic Product Manufacturing	-3.00	Consumer electronic products demand estimates (literature)
Primary Metal Manufacturing	-0.71	EPA estimates
Fabricated Metal Production	-0.52	EPA estimates
Machinery Manufacturing	-1.37	Average of all manufacturing industries
Transportation Equipment	-2.65	EPA estimates

Source: Complied by BBC Research and Consulting from U.S. Environmental Protection Agency Elasticity Databank, 2005.

Impacts on Case Study Industries — IM1

BBC applied the data described previously in this report to determine direct impacts of higher electricity rates on the case study industries.

Under the IM1 scenario, changes in output would range from $10 to $30 million for the Midwest paper manufacturing industry to $100 to $310 million for the Midwest chemicals industry, in 2003 dollars. There would be no direct impacts on the coal mining industry, as the study team assumed no shifting away from Midwest coal due to IM1 controls.

In total, IM1 would have direct impacts on the case study industries of $440 to $1,340 million.

Because output of the case study industries would be reduced, these industries would purchase less inputs from linked industries and cutbacks in workforce would affect the regional economy. These secondary effects would total $260 to $830 million within the Midwest under IM1. Therefore, the total effect of IM1 from impacts on case study industries is $0.7 to $2.2 billion in reduced output. This change in output would result in 3,320 to 10,730 fewer jobs in the Midwest. Job impacts could be particularly large in plastic and rubber manufacturing and fabricated metals manufacturing.

Impacts of electricity cost increases from IM1 on case study industries would be lowest in Illinois ($40 to $130 million in reduced output) and highest in Indiana (up to $790 million in reduced output). Job losses in Indiana and Ohio could exceed 3,000 in each state.

Exhibit IV-4.
Impact of proposed IM1 scenario on annual case study industry output and jobs (2012)

Losses by Industry	*Output (2003 $ millions)*	*Jobs*
Food Product	$20 – $150	60 – 360
Paper	$10 – $30	50 – 80
Chemicals	$100 – $310	160 – 520
Plastic/Rubber	$70 – $200	260 – 810
Primary Metals	$40 – $120	130 – 390
Fabricated Metals	$20 – $130	90 – 600
Machinery	$30 – $100	110 – 350
Computers/Electronics	$40 – $80	70 – 140
Transportation Equipment	$110 – $240	200 – 420
Coal Mining	$0 – $0	0 – 0
10 Industry Total	***$440 – $1,340***	***1,130 – 3,680***
Secondary Impacts	***$260 – $830***	***2,190 – 7,060***
Regional Total	***$700 – $2,170***	***3,320 – 10,730***

Losses by State	*Output (2003 $ millions)*	*Jobs*
Illinois	$40 – $130	130 – 480
Indiana	$260 – $790	1,260 – 4,060
Michigan	$140 – $400	640 – 1,890
Ohio	$200 – $630	1,010 – 3,300
Wisconsin	$60 – $220	270 – 1,010
Regional Total	***$700 – $2,170***	***3,320 – 10,730***

Note: Totals may not add due to rounding.

Impacts on Case Study Industries — IM2

Impacts on case study industries would be about 50 percent greater under the IM2 scenario compared with IM1. Direct impacts on the ten case study industries would range from about $0.7 to $2.1 billion in reduced output (2002 dollars). Including secondary impacts (case study industries reducing their purchases of inputs), Midwest economic output could fall by $1.1 to $3.4 billion.

The distribution of impacts among case study industries is similar between IM1 and IM2. The plastic and rubber manufacturing industry and the fabricated metals industry could face the largest job losses. Total job losses could reach nearly 17,000 employees for the region. As with IM1, there would be no direct impacts on the coal mining industry, as the study team assumed no shifting away from Midwest coal due to IM2 controls.

Impacts of electricity cost increases from IM2 on case study industries would be lowest in Wisconsin ($0.1 to $0.3 billion in reduced output) and highest in Indiana ($0.4 to 1.1 billion in reduced output). Job losses could exceed 3,000 in Indiana, Ohio and Michigan.

Exhibit IV-5.
Impact of proposed IM2 scenario on annual case study industry output and jobs (2012)

Losses by Industry	*Output (2003 $ millions)*	*Jobs*
Food Product	$40 – $240	90 – 610
Paper	$10 – $40	30 – 120
Chemicals	$150 – $500	260 – 840
Plastic/Rubber	$100 – $310	400 – 1,240
Primary Metals	$60 – $170	180 – 560
Fabricated Metals	$30 – $200	150 – 950
Machinery	$50 – $150	190 – 570
Computers/Electronics	$60 – $130	110 – 230
Transportation Equipment	$170 – $350	300 – 620
Coal Mining	$0 – $0	0 – 0
10 Industry Total	***$660 – $2,090***	***1,700 – 5,750***
Secondary Impacts	***$400 – $1,300***	***3,290 – 11,060***
Regional Total	***$1,060 – $3,390***	***4,990 – 16,810***

Losses by State	*Output (2003 $ millions)*	*Jobs*
Illinois	$160 – $590	600 – 2,290
Indiana	$360 – $1,120	1,810 – 5,950
Michigan	$240 – $670	1,090 – 3,310
Ohio	$220 – $690	1,090 – 3,730
Wisconsin	$90 – $320	400 – 1,540
Regional Total	***$1,060 – $3,390***	***4,990 – 16,810***

Note: Totals may not add due to rounding.

Impacts on Case Study Industries — EGU1/EGU2 Without Replacement Power Costs

The EGU1 and EGU2 LADCO control scenarios would have a similar effect on case study industries, excluding any additional costs of replacing power from early retirement of certain generating units. Under EGU1 or EGU2 (without power replacement), output of case study industries could fall by $2.4 to $4.7 billion. These direct impacts would trigger secondary impacts of $1.8 to $3.2 billion across the regional economy. In total, Midwest economic output could fall by as much as $7.8 billion under these scenarios from the direct and secondary effects on the ten case study industries. This could mean a loss of up to 38,000 jobs in the Midwest.

As with IM1 and IM2, job losses in the plastic and rubber, fabricated metals and chemicals industries could be most severe. However, EGU1/EGU2 would trigger Midwest power plants to substitute Wyoming coal for Midwest coal, leading to sharp cutbacks in output and employment in Midwest coal mines. Output in coal mining could be $1.3 billion lower and about 3,900 mining jobs could be lost in the Midwest.

Compared with the impacts of IM1 and IM2 on case study industries, the impacts of EGU1/EGU2, without power replacement, would be higher in each Midwest state. For example, Illinois would lose at least 2,300 jobs and perhaps as many as 5,200 jobs under EGU1/EGU2 (without replacement power). Indiana could lose as many as 14,700 jobs.

Exhibit IV-6.
Impact of proposed EGU1/EGU2 scenario, without power replacement costs, on annual case study industry output and jobs (2013)

Losses by Industry	*Output (2003 $ millions)*	*Jobs*
Food Product	$60 – $380	140 – 960
Paper	$30 – $60	100 – 180
Chemicals	$250 – $810	410 – 1,340
Plastic/Rubber	$160 – $500	640 – 1,970
Primary Metals	$90 – $280	290 – 890
Fabricated Metals	$50 – $320	230 – 1,490
Machinery	$80 – $240	290 – 880
Computers/Electronics	$100 – $220	170 – 360
Transportation Equipment	$250 – $530	430 – 910
Coal Mining	$1,330 – $1,330	3,880 – 3,880
10 Industry Total	***$2,400 – $4,670***	***6,590 – 12,850***
Secondary Impacts	***$1,760 – $3,180***	***13,270 – 25,300***
Regional Total	***$4,160 – $7,840***	***19,860 – 38,150***

Losses by State	*Output (2003 $ millions)*	*Jobs*
Illinois	$640 – $1,370	2,360 – 5,170
Indiana	$1,640 – $2,900	8,080 – 14,730
Michigan	$300 – $820	1,330 – 3,990
Ohio	$1,460 – $2,330	7,590 – 12,300
Wisconsin	$120 – $420	510 – 1,970
Regional Total	***$4,160 – $7,840***	***19,860 – 38,150***

Note: Totals may not add due to rounding.

The study team also examined EGU1 with net power replacement costs. Because the impact on electricity rates resulting from EGU1 would be somewhat lower with power replacement than without power replacement, effects on regional output and employment are slightly less under this scenario. Impacts on the Midwest coal mining industry are unchanged.

Case study industry impacts of EGU1, with power replacement, would be a loss of $4.1 to $7.6 billion in regional output and up to 37,000 jobs. These estimates include secondary effects from cutbacks in case study industry purchases from other sectors.

The distribution of impacts among economic sectors and states under EGU1, with power replacement, would be similar to EGU1 without power replacement.

Exhibit IV-7.
Impact of proposed EGU1 scenario, with power replacement costs, on annual case study industry output and jobs (2013)

Losses by Industry	*Output (2003 $ millions)*	*Jobs*
Food Product	$50 – $370	130 – 910
Paper	$30 – $50	100 – 170
Chemicals	$240 – $790	390 – 1,290
Plastic/Rubber	$150 – $480	610 – 1,900
Primary Metals	$90 – $280	290 – 870
Fabricated Metals	$50 – $310	230 – 1,420
Machinery	$80 – $230	270 – 840
Computers/Electronics	$100 – $200	170 – 340
Transportation Equipment	$240 – $510	420 – 880
Coal Mining	$1,330 – $1,330	3,880 – 3,880
10 Industry Total	***$2,360 – $4,530***	***6,490 – 12,490***
Secondary Impacts	***$1,730 – $3,090***	***13,060 – 24,610***
Regional Total	***$4,090 – $7,620***	***19,550 – 37,100***
Losses by State	*Output (2003 $ millions)*	*Jobs*
Illinois	$630 – $1,300	2,300 – 4,910
Indiana	$1,620 – $2,880	7,970 – 14,610
Michigan	$280 – $770	1,260 – 3,720
Ohio	$1,450 – $2,300	7,560 – 12,150
Wisconsin	$110 – $370	450 – 1,720
Regional Total	***$4,090 – $7,620***	***19,550 – 37,100***

Note: Totals may not add due to rounding.

Impacts on Case Study Industries — EGU2

EGU2, with power replacement, would have the most severe impact on case study industries of the scenarios studied. From $5 to $10 billion of regional output could be lost and up to 50,000 jobs eliminated under this scenario.

EGU2, with power replacement, would result in significantly higher electricity costs than even EGU1, with power replacement. This would be especially true for Illinois, Michigan and Wisconsin. Power rates in Indiana would go up 29 percent under EGU2, with power replacement, compared with 22 percent with EGU1.

Impacts would be greater for each case study industry in the Midwest. EGU2's impacts on Midwest states could reach 18,700 lost jobs in Indiana and 13,700 lost jobs in Ohio. The state with the lowest job losses, Wisconsin, could still see losses of 3,600 jobs.

Coal mining output would drop by $1.5 billion in the Midwest under EGU2, with power replacement. About 4,400 coal mining industry jobs would be lost in the Midwest, or more than half of current employment in this sector.

Exhibit IV-8.
Impact of proposed EGU2 scenario, with power replacement costs, on annual case study industry output and jobs (2013)

Losses by Industry	*Output (2003 $ millions)*	*Jobs*
Food Product	$80 – $550	200 – 1,360
Paper	$50 – $80	150 – 270
Chemicals	$340 – $1,100	560 – 1,810
Plastic/Rubber	$220 – $680	860 – 2,680
Primary Metals	$120 – $370	390 – 1,170
Fabricated Metals	$70 – $440	330 – 2,060
Machinery	$110 – $340	410 – 1,230
Computers/Electronics	$140 – $300	240 – 500
Transportation Equipment	$340 – $720	590 – 1,240
Coal Mining	$1,490 – $1,490	4,360 – 4,360
10 Industry Total	***$2,960 – $6,070***	***8,080 – 16,680***
Secondary Impacts	***$2,130 – $4,080***	***16,190 – 32,730***
Regional Total	***$5,090 – $10,150***	***24,270 – 49,400***
Losses by State	*Output (2003 $ millions)*	*Jobs*
Illinois	$850 – $1,930	3,130 – 7,340
Indiana	$1,980 – $3,640	9,800 – 18,660
Michigan	$450 – $1,250	2,060 – 6,100
Ohio	$1,590 – $2,580	8,340 – 13,700
Wisconsin	$220 – $760	940 – 3,600
Regional Total	***$5,090 – $10,150***	***24,270 – 49,400***

Note: Totals may not add due to rounding.

SECTION V.
Impacts of Higher Costs for Households

Impacts of Higher Costs for Households — Output

The LADCO control scenarios could result in electricity cost increases for Midwest households of up to $2.8 billion in 2013 (2003 dollars). This shift of consumer expenditures toward electricity purchases would leave households less money to spend on other items.

The impact on regional output from a $2.8 billion reduction in household spending on non-electricity items does not equal $2.8 billion. One reason is that the increases in electricity costs would not evenly fall on all types of households. Each income group, for example, spends a different portion of its income on electricity, and increasing those expenditures would have a different effect on purchases of other goods and services. (BBC modeled impacts for nine different income classes.) Further, not all of the displaced consumer spending would have gone for goods and services produced by Midwest establishments. To the extent that households will reduce some of their purchases from companies within the Midwest, reduced spending creates a ripple effect through the regional economy.

BBC modeled these relationships using the IMPLAN model. The result of a $2.8 billion increase in consumer spending on electricity and corresponding reduction of spending on other goods and services would translate into $3.9 billion of reduced output in the Midwest (EGU2, with replacement power). The smallest impact would be a $1.2 billion reduction in regional output under IM1. Impacts from higher electricity rates for consumers vary among states depending on the size of the state and percentage increase in rates. Because it would face the highest rate increases, impacts from reduced household spending would be greatest in Indiana.

Exhibit V-1.
Annual impacts on output from reduced household spending (millions of 2003 dollars)

	2012		2013		
			Without Replacement Power	With Replacement Power	
	IM1	IM2	EGU1/EGU2	EGU1	EGU2
Illinois	$90	$390	$670	$630	$990
Indiana	$350	$480	$800	$800	$1,040
Michigan	$240	$380	$490	$430	$700
Ohio	$380	$400	$720	$720	$820
Wisconsin	$110	$150	$200	$170	$360
Region	***$1,160***	***$1,820***	***$2,870***	***$2,760***	***$3,910***

Note: Totals may not add due to rounding.
Source: BBC Research and Consulting.

Based on the projected changes in output shown in Exhibit V-1, BBC used the IMPLAN model to estimate job losses resulting from higher electricity rates for households. Exhibit V-2 presents these impact results.

Under IM1, about 13,000 jobs could be lost in the region from the combined direct and secondary effects of the shift in household spending. IM2 could result in 21,000 jobs lost. EGU1, with replacement power, and EGU1/EGU2, without replacement power, would eliminate about 32,000 to 33,000 jobs in the region from the higher household electricity rates. EGU2, with replacement power, could lead to 45,000 fewer jobs in the region.

Employment impacts of IM1 would range from about 900 jobs in Illinois to 4,500 jobs in Ohio. Job losses would exceed 4,000 in each state except Wisconsin under IM2. The impact of EGU1/EGU2, without replacement power, would range from 2,400 jobs in Wisconsin to almost 10,000 jobs in Indiana. Effects of EGU1, with replacement power, would be similar.

EGU2, with replacement power, would have the greatest impact on each state's employment. Economic losses could exceed 12,000 jobs in Indiana and reach about 10,000 jobs in both Illinois and Ohio. The drop in total employment in Wisconsin could exceed 4,000 jobs. Michigan employment could be reduced by 8,000 jobs.

Exhibit V-2.
Impact on jobs from reduced household spending

	2012		2013		
			Without Replacement Power	With Replacement Power	
	IM1	IM2	EGU1/EGU2	EGU1	EGU2
Illinois	890	4,060	6,940	6,500	10,270
Indiana	4,120	5,780	9,600	9,540	12,480
Michigan	2,630	4,350	5,330	5,010	7,990
Ohio	4,490	4,870	8,820	8,630	9,960
Wisconsin	1,270	1,880	2,360	2,110	4,350
Region	***13,400***	***20,940***	***33,050***	***31,790***	***45,060***

Note: Totals may not add due to rounding.
Source: BBC Research & Consulting.

SECTION VI.
Regional Economic Impact

Regional Economic Impact — Total Output

BBC combined and summarized the direct effects on case study industries, the secondary impacts from these effects and the impacts from household electricity rate increases for each LADCO control scenario. Impacts on Midwest output would be in the range of $1.9 to $3.3 billion under IM1 and from $2.9 to $5.2 billion under IM2 in 2012. Impacts of EGU1/EGU2, without replacement power, and EGU1, with replacement power, could be about $7 billion to more than $10 billion in reduced regional output.

EGU2, with replacement power, could have up to a $6.1 billion impact on case study industry output, a $4.1 billion secondary effect from the rate increases for case study industries, and a nearly $3.9 billion impact on regional output from electricity rate increases for Midwest households. In total, the impact of this LADCO control scenario on Midwest annual output could reach $14.1 billion (2003 dollars). Under the alternative assumption that local firms' could pass on a portion of their cost increases to their customers, the impacts of EGU2, with power replacement, would be $9 billion.

Because BBC studied only rate impacts on households and case study industries, and did not fully model direct effects on all industries and all the intraregional linkages, the full effects of each scenario could be higher than reported here.

Exhibit VI-1.
Impacts of proposed LADCO EGU control measures on annual Midwest region output (millions of 2003 dollars)

	2012		2013		
			Without Replacement Power	With Replacement Power	
	IM1	*IM2*	*EGU1/EGU2*	*EGU1*	*EGU2*
Case Study Industries	$440 – $1,340	$660 – $2,090	$2,400 – $4,670	$2,360 – $4,530	$2,960 – $6,070
Secondary Impacts	$260 – $830	$400 – $1,300	$1,760 – $3,180	$1,730 – $3,090	$2,130 – $4,080
Residential Impacts	$1,160	$1,820	$2,870	$2,760	$3,910
Total	***$1,860 – $3,330***	***$2,880 – $5,210***	***$7,030 – $10,710***	***$6,850 – $10,380***	***$9,000 – $14,060***

Note: Totals may not add due to rounding.

Source: BBC Research and Consulting.

Regional Economic Impact — State Output

The $9 to $14 billion impact on regional output under EGU2, with replacement power, would be distributed across each of the five states in the region. Economic output of Indiana could fall by up to $4.7 billion and output of Illinois and Ohio could drop by as much as $3 billion. Michigan output could be reduced by $2 billion and Wisconsin economic activity could drop by $1 billion.

The relative distribution of economic impacts are similar for other LADCO control scenarios, with certain exceptions. In Wisconsin, EGU2 would double the economic impacts created by EGU1. IM1 would have relatively small effects on Illinois, but IM2 impacts in that state would be similar to impacts in Michigan and Ohio.

Exhibit VI-2.
Impacts of proposed LADCO EGU control measures on annual Midwest state output (millions of 2003 dollars)

	2012		2013		
			Without Replacement Power	With Replacement Power	
	IM1	*IM2*	*EGU1/EGU2*	*EGU1*	*EGU2*
Illinois	$130 – $220	$550 – $980	$1,310 – $2,040	$1,260 – $1,930	$1,840 – $2,920
Indiana	$610 – $1,140	$840 – $1,600	$2,440 – $3,700	$2,420 – $3,680	$3,020 – $4,680
Michigan	$380 – $640	$620 – $1,050	$790 – $1,310	$710 – $1,200	$1,150 – $1,950
Ohio	$580 – $1,010	$620 – $1,090	$2,180 – $3,050	$2,170 – $3,020	$2,410 – $3,400
Wisconsin	$170 – $330	$240 – $470	$320 – $620	$280 – $540	$580 – $1,120
Total	***$1,860 – $3,330***	***$2,880 – $5,210***	***$7,030 – $10,710***	***$6,850 – $10,380***	***$9,000 – $14,060***

Note: Totals may not add due to rounding.
Source: BBC Research and Consulting.

Regional Economic Impact — Total Jobs

The assessment of losses of regional output ranged from $1.9 billion (minimum impact of IM1) to $14 billion (maximum effect of EGU2, with replacement power). The corresponding job losses would be a low of 16,700 to a high of 94,500.

Employment impacts under IM2 could reach nearly 38,000 jobs lost, which would double under EGU1/EGU2, without replacement power. EGU1, with replacement power, could result in 51,000 to 69,000 jobs lost.

Because BBC studied only rate impacts on households and case study industries, and did not fully model all intraregional linkages, the full effects could be higher.

Exhibit VI-3.
Impacts of proposed LADCO EGU control measures on Midwest region jobs

	2012		2013		
			Without Replacement Power	With Replacement Power	
	IM1	IM2	EGU1/EGU2	EGU1	EGU2
Case Study Industries	1,130 – 3,680	1,700 – 5,750	6,590 – 12,850	6,490 – 12,490	8,080 – 16,680
Secondary Impacts	2,190 – 7,060	3,290 – 11,060	13,270 – 25,300	13,060 – 24,610	16,190 – 32,730
Residential Impacts	13,400	20,940	33,050	31,790	45,060
Total	***16,720 – 24,140***	***25,930 – 37,750***	***52,910 – 71,200***	***51,340 – 68,890***	***69,330 – 94,460***

Note: Totals may not add due to rounding.

Source: BBC Research and Consulting.

Regional Economic Impact — State Jobs

Job losses would be largest in Indiana and Ohio under each LADCO control scenario. A minimum of 5,000 jobs would be lost in Indiana under IM1. Under EGU2, with replacement power, total employment in Indiana could be reduced by as much as 31,000 jobs. Similarly, Ohio employment losses could be as low as 5,500 under IM1 and could exceed 23,000 under EGU2 (with replacement power).

Exhibit VI-4.
Impacts of proposed LADCO EGU control measures on Midwest jobs by state

	2012		2013		
			Without Replacement Power	With Replacement Power	
	IM1	*IM2*	*EGU1/EGU2*	*EGU1*	*EGU2*
Illinois	1,020 – 1,370	4,660 – 6,350	9,300 – 12,110	8,800 – 11,410	13,400 – 17,610
Indiana	5,380 – 8,180	7,590 – 11,730	17,680 – 24,330	17,510 – 24,150	22,280 – 31,140
Michigan	3,270 – 4,520	5,440 – 7,660	6,630 – 9,290	6,270 – 8,730	10,050 – 14,090
Ohio	5,510 – 7,800	5,960 – 8,600	16,410 – 21,120	16,190 – 20,780	18,300 – 23,660
Wisconsin	1,540 – 2,280	2,280 – 3,420	2,870 – 4,330	2,560 – 3,830	5,290 – 7,950
Total	***16,720 – 24,140***	***25,930 – 37,750***	***52,910 – 71,200***	***51,340 – 68,890***	***69,330 – 94,460***

Note: Totals may not add due to rounding.
Source: BBC Research and Consulting.

Regional Economic Impact — Labor Income

BBC translated job losses into lost labor income in each state. The income per job figures are from IMPLAN. Income is expressed in 2003 dollars.

As shown in Exhibit VI-5, about $0.6 to $1.0 billion in labor income would be lost under IM-1 in the Midwest. Up to $1.6 billion in labor income would be lost under IM-2.

EGU1/EGU2, without replacement power, and EGU1, with replacement power, would have similar impacts on Midwest labor income. Under these scenarios, labor income would be in the range of $2 to $3 billion lower than baseline projections.

EGU2, with replacement power, could reduce regional labor income by up to $4 billion. Impacts would be greatest in Indiana under this and most of the other scenarios.

Exhibit VI-5.
Impacts of proposed LADCO EGU control measures on annual Midwest region labor income (millions of 2003 dollars)

	2012		*2013*		
			Without Replacement Power	*With Replacement Power*	
	IM1	*IM2*	*EGU1/EGU2*	*EGU1*	*EGU2*
Illinois	$50 – $70	$230 – $310	$480 – $630	$450 – $590	$720 – $940
Indiana	$190 – $310	$270 – $450	$700 – $980	$690 – $970	$870 – $1,250
Michigan	$140 – $200	$230 – $340	$280 – $410	$260 – $380	$420 – $620
Ohio	$200 – $300	$210 – $330	$630 – $830	$620 – $820	$680 – $910
Wisconsin	$60 – $90	$90 – $140	$110 – $180	$100 – $160	$210 – $330
Total	***$640 – $960***	***$1,030 – $1,560***	***$2,200 – $3,020***	***$2,130 – $2,920***	***$2,900 – $4,040***

Note: Totals may not add due to rounding.
Source: BBC Research and Consulting.

APPENDIX A.
Industry Profiles

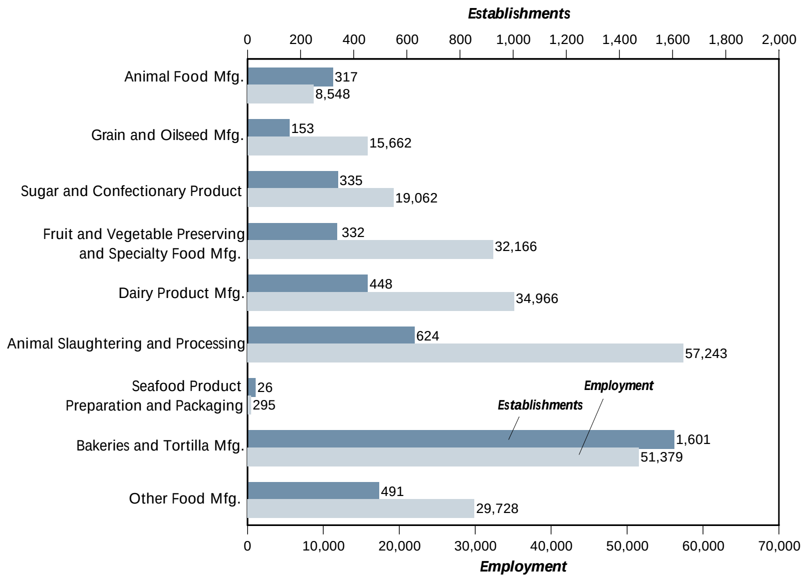
A1. Food Industry

Food Industry — Introduction

The food manufacturing industry employed about 250,000 people in the five-state region in 2002. Approximately 4,300 establishments made food products in these five states according to the U.S. Census Bureau.

As shown in Figure A1-1, federal agencies divide the food manufacturing industry into nine sectors. Plants that slaughter and process animals account for the most jobs in the Midwest food industry. Establishments that make bakery goods and tortillas are the second largest employer in this industry in the Midwest. Dairy products manufacturing is the third largest component of the Midwest food industry.

Figure A1–1.
Midwest establishments and employment in the food manufacturing sector, 2002



Source: U.S. Census Bureau, EPCD, County Business Patterns.

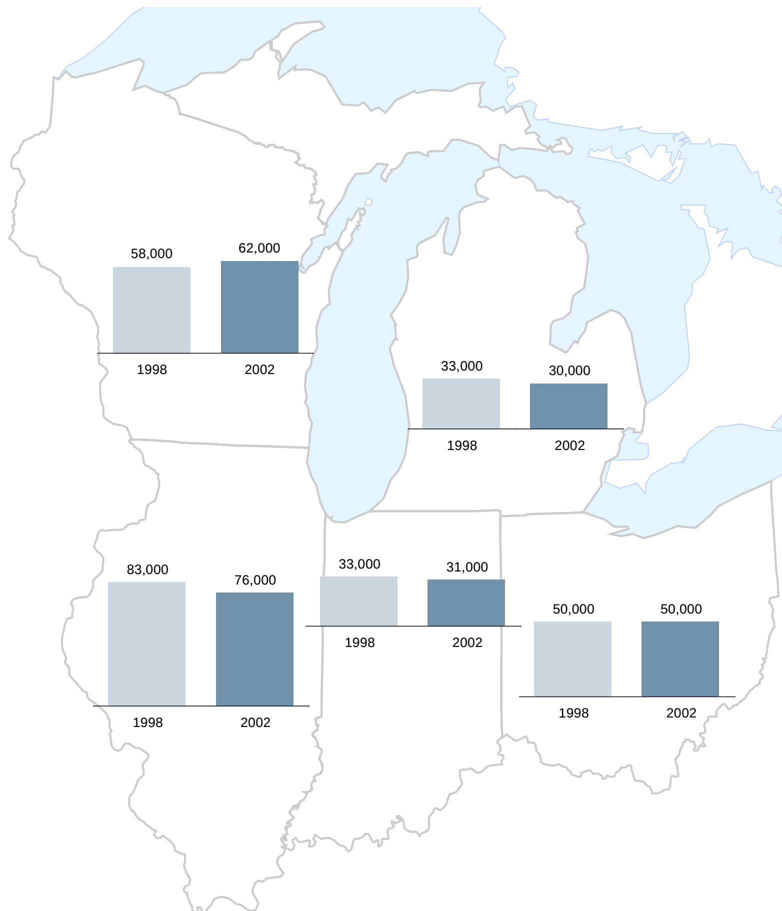
Food Industry — Employment Trends

Employment in the food manufacturing industry in the five-state region ranged from 30,000 jobs in Michigan to about 76,000 jobs in Illinois in 2002.

Fierce competition has led food manufacturing plants to invest in technologically advanced machinery to be more productive. Increased automation throughout the industry has led to a 3 percent decrease in jobs between 1998 and 2002. Illinois lost 7,500 jobs over the four-year period; Michigan and Indiana experienced smaller job losses. In contrast, the food manufacturing industry in Wisconsin added 4,500 jobs between 1998 and 2002. Increased demand for diary products, especially cheese, may have triggered the job increase in the state.

Figure A1-2 shows County Business Patterns data on total employment in the food manufacturing industry for 1998 and 2002 for each Midwestern state.

Figure A1–2.
Employment in the food industry



Source: U.S. Census Bureau, EPCD, County Business Patterns.

Food Industry — Largest Employers

Dun & Bradstreet data show 13 food manufacturing establishments in the Midwest with at least 1,200 employees. Four of the large employers are located in Wisconsin and four are in Illinois.

Figure A1-3 shows the locations of the largest food manufacturing employers according to Dun & Bradstreet.

Figure A1–3.
Food establishments with 1,200+ employees

Source: Dun & Bradstreet Marketplace.

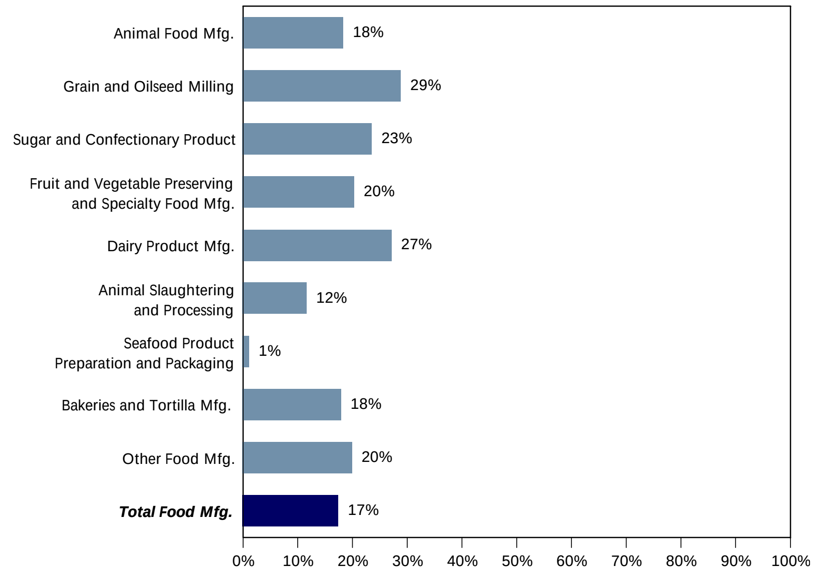
Food Industry — Share of U.S. Employment

The Midwest accounts for about 17 percent of total U.S. employment in the food manufacturing industry.

The region accounts for over a quarter of the national employment in grain and oilseed milling as well as in dairy products manufacturing, as shown in Figure A1-4. The region accounts for only 1 percent of the nation's seafood product preparation and packaging.

Illinois is one of the leading states in animal slaughtering and processing, whereas Wisconsin accounts for almost one-third of cheese manufacturing jobs in the nation.

Figure A1–4.
Midwest share of U.S. food employment, 2002



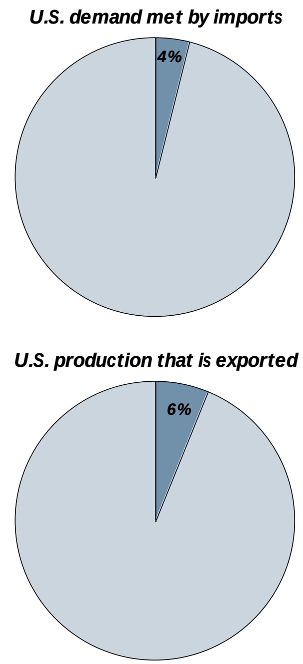
Source: U.S. Census Bureau, EPCD, County Business Patterns.

Food Industry — Global Competition

The U.S. is largely self-sufficient in meeting domestic demands from the food industry. In 2001, 4 percent of the total U.S. demand for food products was met by imports, and 6 percent of the food products produced in the U.S. were exported.

Future growth in the U.S. food manufacturing industry will primarily come from domestic growth in demand, usually created by population growth and rising disposable income.

Figure A1–5.
U.S. imports and exports of food output, 2001



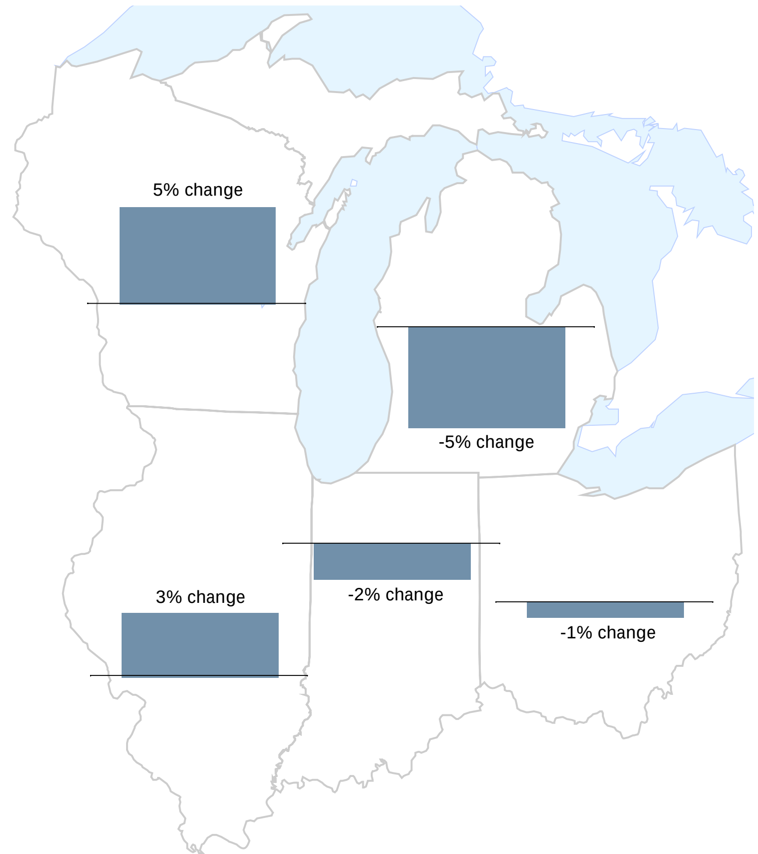
Source: U.S. Census Bureau, International Trade Administration, 2005.

Food Industry — Employment Forecasts

Between 2002 and 2012, employment in the food industry in the five-state region is expected to increase slightly. The food manufacturing industry is expected to add approximately 3,000 jobs, or about 1 percent of the total jobs in 2002.

Figure A1-6 shows the employment change in the food manufacturing sector between 2002 and 2012.

Figure A1–6.
Projected percent change in employment in the food industry, from 2002 to 2012



Source: Illinois Department of Employment Security, Economic Information & Analysis Division; Indiana Department of Workforce Development; Michigan Department of Labor and Economic Growth, Bureau of Labor Market Information and Strategic Initiatives; Ohio Department of Job and Family Services, Bureau of Labor Market Information; and Wisconsin Department of Workforce Development.

A2. Paper Industry

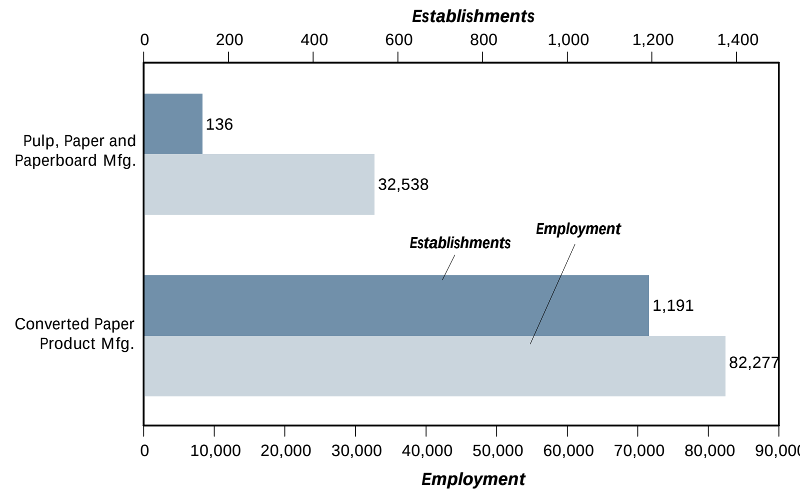
Paper Industry — Introduction

The paper manufacturing industry in the Midwest employed about 115,000 people in 2002. The U.S. Census Bureau estimates approximately 1,300 paper manufacturing establishments in 2002 in these five states.

The paper industry divides into two industry groups: (a) pulp mills, paper mills and paperboard mills that use wood chips and used paper to manufacture paper products and (b) plants that cut, shape and coat paper to make converted paper products. Some establishments integrate both types of paper manufacturing.

As shown in Figure A2-1, the pulp, paper and paperboard mills subsector accounts for over 32,000 jobs in the Midwest in 2002. The converted paper product manufacturing is larger, employing approximately 82,000 people in the five-state region.

Figure A2–1.
Midwest establishments and employment in the paper sector, 2002



Source: U.S. Census Bureau, EPCD, County Business Patterns.

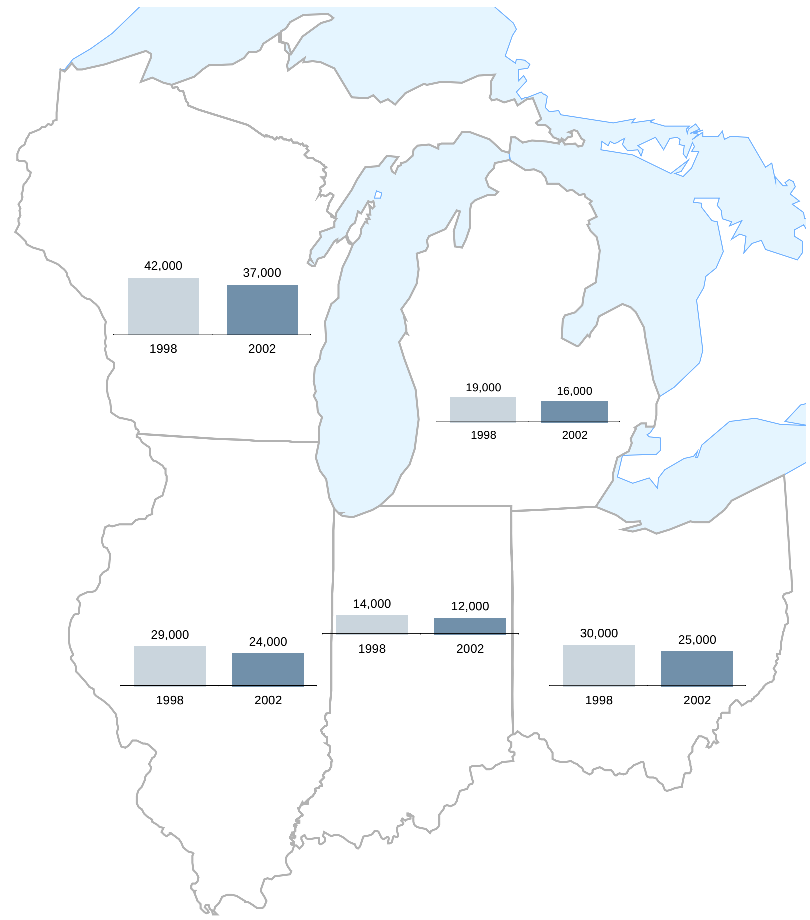
Paper Industry — Employment Trends

U.S. Census Bureau County Business Pattern data indicate that employment in 2002 in the entire paper industry varied from 12,000 workers in Indiana to more than 37,000 employees in Wisconsin.

The paper industry has suffered job losses over the last decade due to consolidations, phasing out of less efficient operations and advancements in automation. Between 1998 and 2002, the paper industry in the U.S. lost about 72,000 jobs, 19,000 of which were in the Midwest.

Between 1998 and 2002, more than 5,000 people in the paper industry lost jobs in Illinois, while more than 4,000 similar jobs were eliminated in Ohio and in Wisconsin. Figure A2-2 shows County Business Patterns data for 1998 and 2002 by state.

Figure A2–2.
Employment in the paper industry



Source: U.S. Census Bureau, EPCD, County Business Patterns.

Paper Industry — Largest Employers

Dun & Bradstreet data identify 13 paper manufacturing establishments in the Midwest with at least 800 employees. The majority of the large manufacturing establishments are located in Wisconsin.

Figure A2-3 shows the locations of the largest paper manufacturing employers in the Midwest.

Figure A2–3.
Paper establishments with 800+ employees

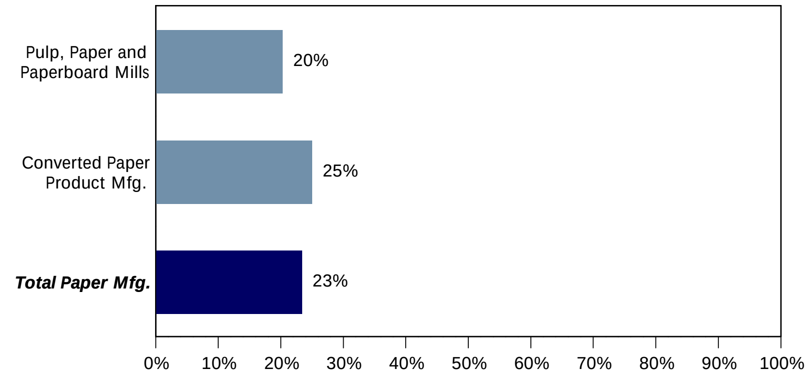
Source: Dun & Bradstreet Marketplace.

Paper Industry — Share of U.S. Employment

Wisconsin has led the U.S. in papermaking for almost 50 years. The state ranked second in total employment in paper manufacturing industry in 2002, according to the County Business Patterns data. In total, the Midwest region accounts for nearly one-quarter of national employment in the paper manufacturing industry.

The Midwest's share of national paper industry employment is highest for converted paper product manufacturing, as is shown in Figure A2-4.

Figure A2–4.
Midwest share of U.S. paper sector employment, 2002



Source: U.S. Census Bureau, EPCD, County Business Patterns.

Paper Industry — Global Competition

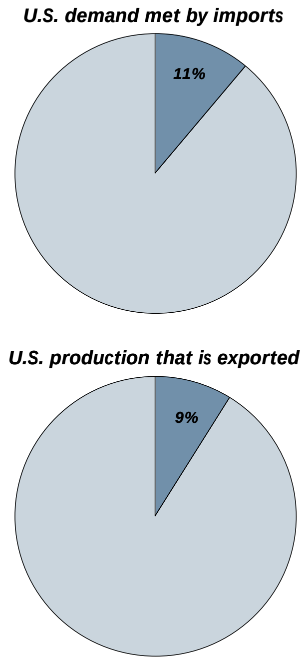
In recent years, the demand for paper products has registered an average annual growth of 3 percent in world markets, while growth in domestic demand is about 7 percent annually. The United States is by far the largest producer and consumer of paper products.

Imports and exports of paper products for the U.S. are smaller than the trade within other sectors examined in this report. As is shown in Exhibit A2-5, 11 percent of the nation's paper demand was met by imports in 2001, whereas 9 percent of the paper products produced in the U.S. were exported.

The health of the paper industry depends upon the overall health of the economy; for example, demand for paper declines during a recession. The health of the paper industry is also highly dependent upon newspaper and journal circulation. Electronic storage and transmission of data has not yet resulted in a decline in paper usage; in fact, just the opposite has happened—documents are easier to produce and print.

The challenges that face the U.S. pulp and paper industry include: the industry's competitiveness within the global economy, dramatic increases in input costs (particularly wood chips), shifting markets for output, the demands to incorporate more recycled fiber, concerns about product quality, environmental concerns, increased government regulations, industry access to publicly-owned forest reserves, paper recycling, and the availability of huge amounts of softwoods from Europe.

Figure A2–5.
U.S. imports and exports of paper output, 2001



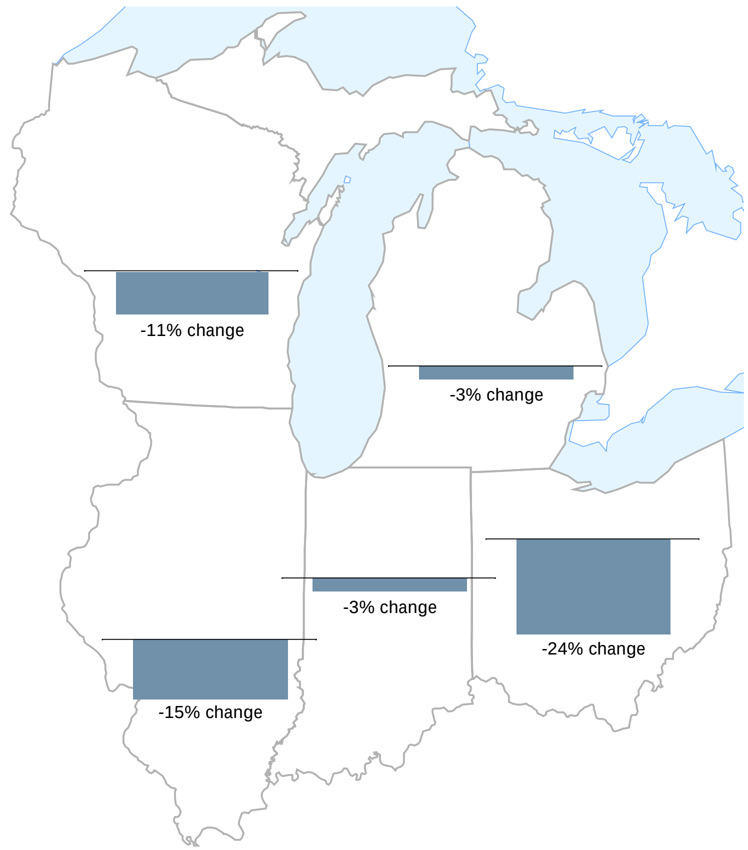
Source: U.S. Census Bureau, International Trade Administration, 2005.

Paper Industry — Employment Forecasts

Marked productivity increases in the paper industry have produced a significant decrease in employment. The U.S. Bureau of Labor Statistics forecasts further job losses in this industry throughout the nation. State-by-state forecasts produced by Midwestern states estimate that the region will see a decline in employment in this industry of more than 10 percent between 2002 and 2012. Job losses in the paper industry are expected to be particularly large in Ohio, where nearly one-quarter of the jobs in this industry in 2002 will not exist in 2012.

Figure A2-6 shows the expected change in employment for this sector between 2002 and 2012.

Figure A2–6.
Projected percent change in employment in the paper industry, from 2002 to 2012



Source: Illinois Department of Employment Security, Economic Information & Analysis Division; Indiana Department of Workforce Development; Michigan Department of Labor and Economic Growth, Bureau of Labor Market Information and Strategic Initiatives; Ohio Department of Job and Family Services, Bureau of Labor Market Information; and Wisconsin Department of Workforce Development.

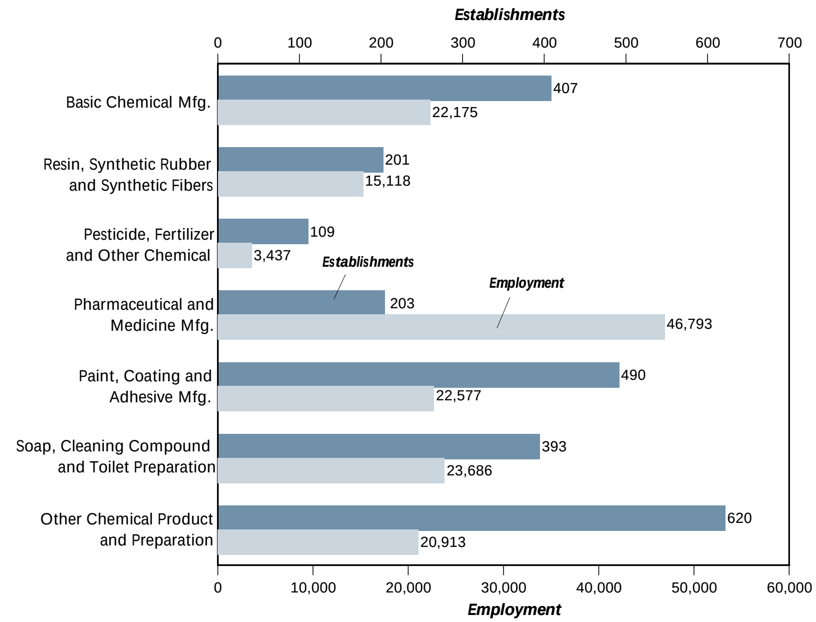
A3. Chemical Industry

Chemical Industry — Introduction

Chemicals are an essential component of the Midwest manufacturing industry, supplying industrial products such as basic chemicals, synthetic rubber and coatings, as well as end products such as medicines. This industry employs approximately 155,000 people in about 2,500 establishments in the region.

Chemical manufacturing is divided into seven different subsectors. As shown in Figure A3-1, pharmaceutical and medicine manufacturing is the largest employer, accounting for over 46,000 jobs in the region. The segment employing the fewest workers in the chemical industry is agricultural chemicals, which supplies farmers and home gardeners with fertilizers, herbicides, pesticides and other related chemicals.

Figure A3–1.
Midwest establishments and employment in the chemicals industry, 2002



Source: U.S. Census Bureau, EPCD, County Business Patterns.

Chemical Industry — Employment Trends

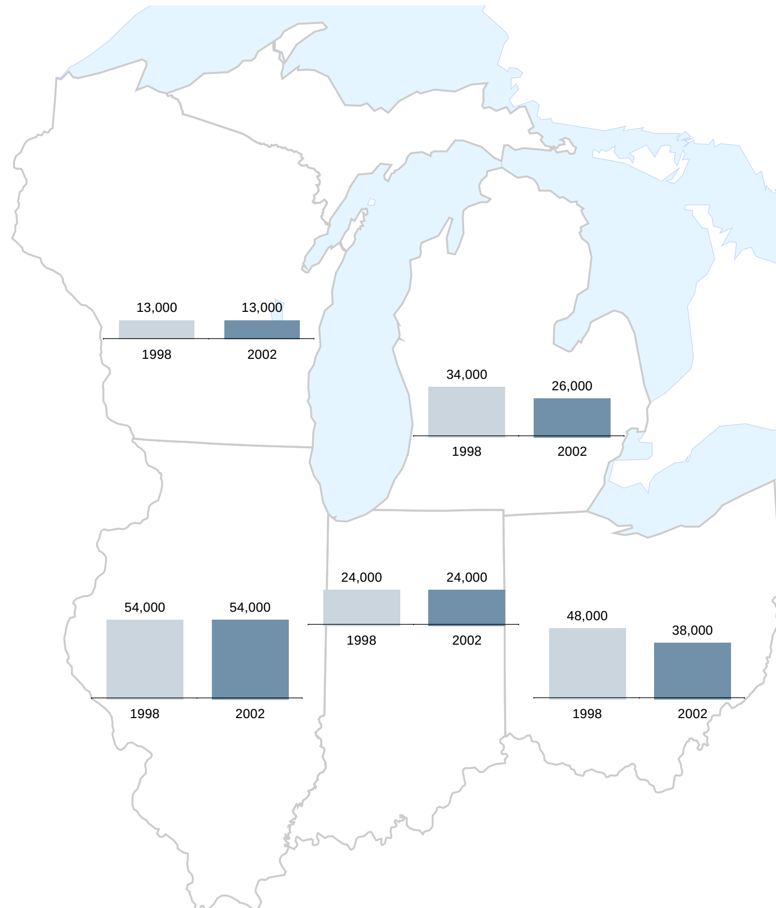
According to U.S. Census Bureau County Business Patterns 2002 data, statewide employment in the chemical industry ranges from 13,000 jobs in Wisconsin to 54,000 jobs in Illinois.

As in other manufacturing industries, employment in the chemical industry has substantially lessened in recent years. Between 1998 and 2002, national employment in this industry saw an 8 percent reduction. The Midwest region's chemicals industry had a10 percent drop in employment, 18,000 jobs, from 1998 to 2002.

Job losses in this industry occurred in primarily two states, Ohio and Michigan. While employment in the chemicals industry held steady in Illinois, Indiana, and Wisconsin between 1998 and 2002, 10,000 jobs were lost in Ohio and 8,000 jobs were lost in Michigan. Increasing global competition, the rising costs of raw materials and energy, and worker productivity gains are a few factors that have contributed to the loss of jobs.

Figure A3-2 shows County Business Patterns data for employment in the chemicals industry in 1998 and 2002 by state.

Figure A3–2. Employment in the chemicals industry



Source: U.S. Census Bureau, EPCD, County Business Patterns

Chemical Industry — Largest Employers

Chemical industry in the five-state region accounts for almost 20 percent of the nation's share of chemical manufacturing establishments, according to the 2002 data from U.S. Bureau of Census. Based on Dun & Bradstreet Marketplace data, there are 13 chemical manufacturing establishments in the five-state region with at least 1,500 employees. Four large employers are located in Indiana, three are in Illinois and three are in Michigan.

Figure A3-3 shows the locations of the largest chemicals manufacturing employers in the Midwest.

Figure A3–3.
Chemicals establishments with 1,500+ employees

Source: Dun & Bradstreet Marketplace.

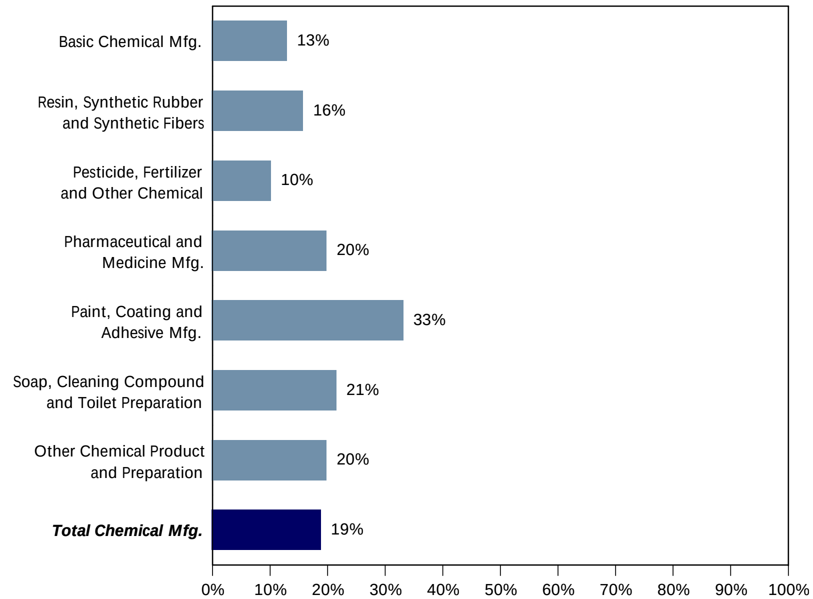
Chemical Industry — Share of U.S. Employment

In 2002, the chemical industry in the Midwest comprised about one-fifth of the nation's employment in the industry.

As seen in Figure A3-4, paint, coatings and adhesive manufacturing in the five-state region accounts for one-third of all the nation's employees in this sector. The region is home to 21 percent of the nation's workers in the soap and cleaning compounds sector and 20 percent of all the U.S. workers in pharmaceutical and medicine manufacturing.

Relatively few of the nation's workers in the pesticide, fertilizer and related agricultural chemical sector are in the Midwest.

Figure A3–4.
Midwest share of U.S. chemicals employment, 2002



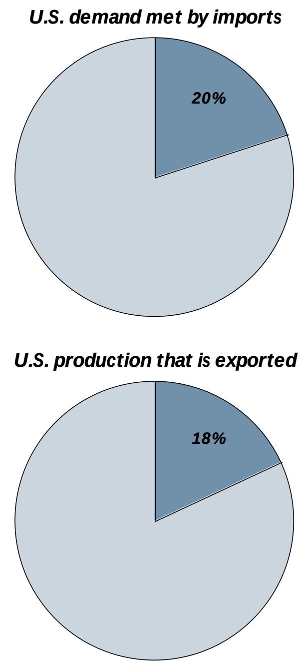
Source: U.S. Census Bureau, EPCD, County Business Patterns.

Chemical Industry — Global Competition

While the U.S. has historically had one of the largest chemicals industries in the world, foreign competition is increasing as the industry has seen dramatic growth in other parts of the globe, particularly in Asia and Latin America. In 2001, 20 percent of U.S. demand for products in the chemical industry was met by imports and 18 percent of U.S. output was exported (see Figure A3-5).

Sales of domestic chemicals recovered in 2004 after a period of relatively slow sales from 2001 to 2003, and exports of chemicals are now increasing. Overall output of the domestic industry is expected to grow, however, increased worker productivity will most likely impede employment gains within the industry.

Figure A3–5.
U.S. imports and exports of chemicals output, 2001



Source: U.S. Census Bureau, International Trade Administration, 2005

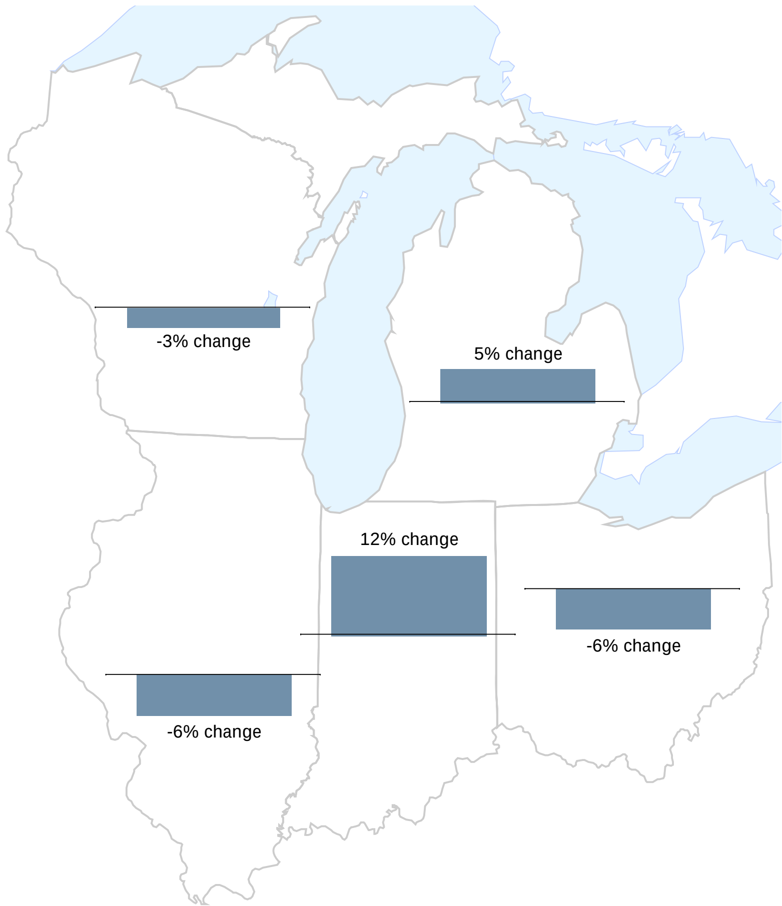
Chemical Industry — Employment Forecasts

Although the output of the chemicals industry is expected to grow, employment in the industry is projected to slightly decline over the 2002-2012 period, continuing the long-term trend of increasing labor productivity in this sector.

By 2012, the five-state region projects employment to decrease by about 1 percent, a loss of approximately 1,500 jobs. Employment in the chemical industry in Ohio, Illinois and Wisconsin is estimated to decrease between 2002 and 2012, employment in Indiana and Michigan is forecasted to increase by 11.9 percent and 5.2 percent, respectively.

Figure A3-6 shows the change in employment in the chemical industry between 2002 and 2012 based on each state's own projections.

Figure A3–6.
Projected percent change in employment in the chemicals industry, from 2002 to 2012



Source: Illinois Department of Employment Security, Economic Information & Analysis Division; Indiana Department of Workforce Development; Michigan Department of Labor and Economic Growth, Bureau of Labor Market Information and Strategic Initiatives; Ohio Department of Job and Family Services, Bureau of Labor Market Information; and Wisconsin Department of Workforce Development.

A4. Plastics and Rubber Industry

Plastics and Rubber Industry — Introduction

The plastics and rubber manufacturing industry employed about 280,000 people in the five-state region in 2002. The U.S. Census Bureau estimates approximately 3,900 rubber and plastics manufacturing establishments in 2002 in these five states.

Firms in the plastics and rubber products manufacturing sector make goods by processing plastic materials and raw rubber. The federal government combines plastics and rubber in the same sector since plastics are increasingly used as a substitute for rubber. However, few establishments manufacture both plastics and rubber products.

As shown in Figure A4-1, most employment in this industry in the Midwest is in plastics manufacturing. This sub-sector accounted for 230,000 jobs in 2002, compared to 54,000 jobs in rubber manufacturing in the five-state area. There were five times as many plastic manufacturing establishments as there were rubber products establishments in the Midwest in 2002.

Figure A4–1.
Midwest establishments and employment in the plastics and rubber sector, 2002

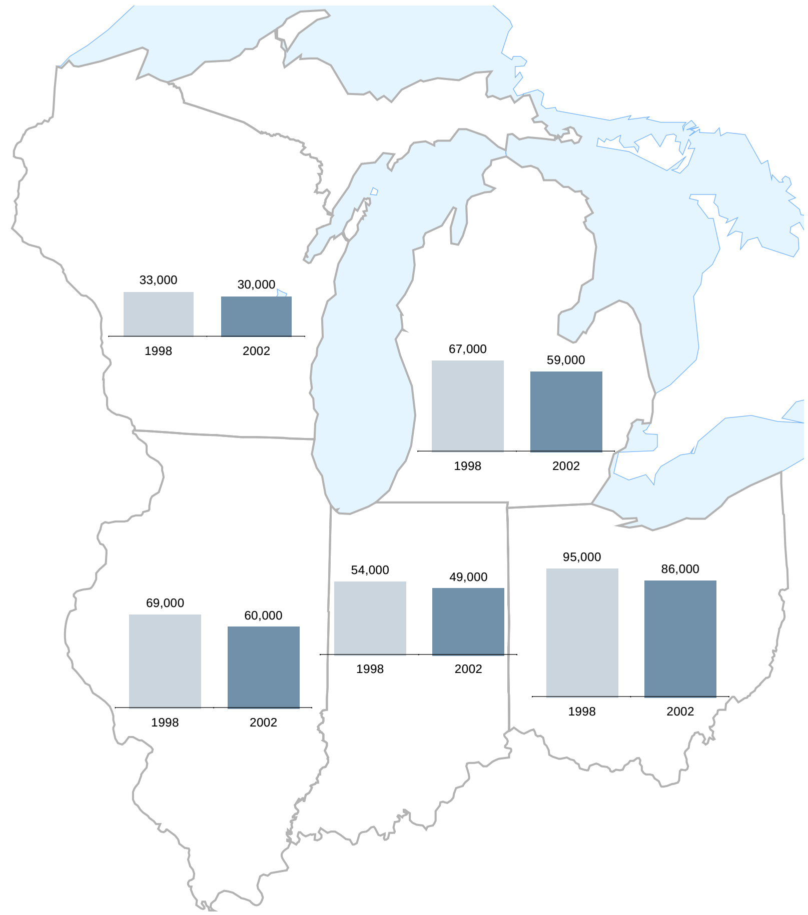
Source: U.S. Census Bureau, EPCD, County Business Patterns.

More plastics and rubber manufacturing jobs are in Ohio than any other Midwest state. According to the U.S. Census Bureau County Business Pattern data, there were 86,000 jobs in this industry in Ohio in 2002.

Between 1998 and 2002, the U.S. plastics and rubber manufacturing industry suffered a job loss of 10 percent. In the five-state region, approximately 35,000 jobs were lost in this sector, a decline of 11 percent. Job losses were largest in Ohio, Michigan and Illinois.

Figure A4-2 shows employment in the plastics and rubber industry for both 1998 and 2002 in the Midwest.

Figure A4–2.
Employment in the plastics and rubber industry



Source: U.S. Census Bureau, EPCD, County Business Patterns.

Plastics and Rubber Industry — Largest Employers

Fifteen plastics and rubber manufacturing establishments in the Midwest have 800 or more employees. Five of the large manufacturing establishments are located in Ohio and five are based in Michigan. Four large employers are in Illinois.

Figure A4-3 shows the locations of the largest plastics and rubber manufacturing employers in the five-state region according to Dun & Bradstreet.

Figure A4–3.
Plastics and rubber establishments with 800+ employees

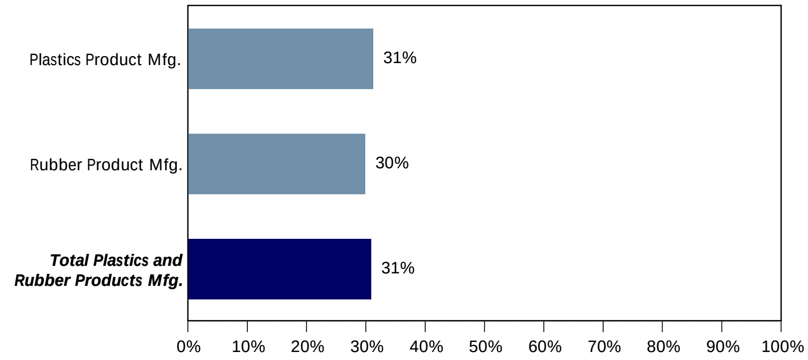
Source: Dun & Bradstreet Marketplace.

Plastics and Rubber Industry — Share of U.S. Employment

Ohio leads the U.S. in employment for the plastics and rubber manufacturing industry. Illinois and Michigan place third and fourth, respectively for employment in this industry.

The five-state region accounts for nearly one-third of the total national employment in the plastics and rubber manufacturing industry, as is shown in Figure A4-4.

Figure A4–4.
Midwest share of U.S. plastics and rubber sector employment, 2002



Source: U.S. Census Bureau, EPCD, County Business Patterns.

Plastics and Rubber Industry — Global Competition

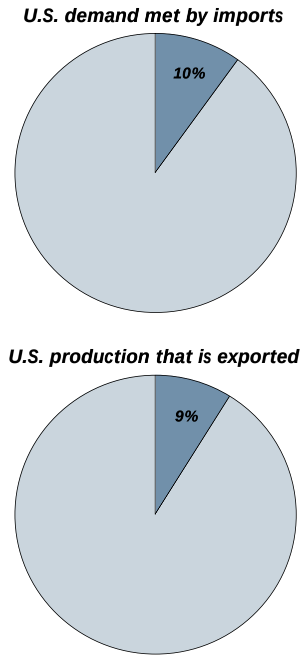
The plastics and rubber industry is a mature global industry. Similar to other manufacturing, the plastics and rubber industry is impacted by factors such as overseas competition, foreign government subsidies for their industries, raw material cost, environmental regulations, recycling and energy costs.

For example, in 1998 U.S. imports of synthetic rubber (70 percent of these products are consumed by the automotive industry) rose 8 percent as additional capacity came on-line in Malaysia and South Korea bringing low-cost synthetic rubber to the global market. Exports fell by 9 percent, in part because of the 1997 currency crisis in Asia. Economic turmoil in Latin American and Russia as well as a strong U.S. dollar also hurt exports in that year.

Current conditions have changed; a weaker dollar and increased demand for rubber in China and other Asian countries has provided a boost to the U.S. plastics and rubber industry.

In 2001, 10 percent of the U.S. demand in this industry was met by imports and 9 percent of the production was exported (see Figure A4-5).

Figure A4–5.
U.S. imports and exports of plastics and rubber output, 2001



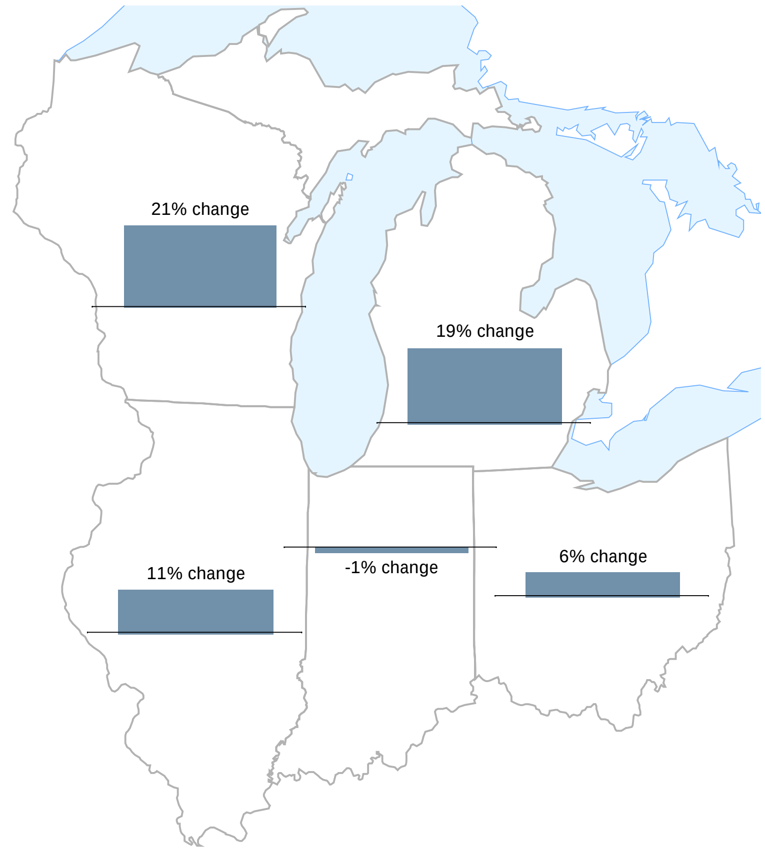
Source: U.S. Census Bureau, International Trade Administration, 2005.

Growth rates in the U.S. plastics and rubber industry slowed significantly toward the end of the 1990's and into 2002. However, the U.S. Bureau of Labor Statistics projects an increase in employment of 130,000 jobs nationally in this industry between 2002 and 2012. These job increases are because of a predicted increase in consumption of these products by the automobile and housing sectors, as well as increases in consumption by the growing economies of Asian countries.

State forecasts for the Midwest indicate employment in this industry will increase by 2012 by about 10 percent. Wisconsin forecasts the greatest percent increase in jobs in this sector by 2012 (adding 20 percent of the 2002 employment), and Illinois, Michigan and Ohio also expect job gains in this sector.

Figure A4-6 shows the total change in employment in the plastics and rubber industry between 2002 and 2012, based on each state's individual projections.

Figure A4–6.
Projected change in employment in the plastics and rubber industry, from 2002 to 2012



Source: Illinois Department of Employment Security, Economic Information & Analysis Division; Indiana Department of Workforce Development; Michigan Department of Labor and Economic Growth, Bureau of Labor Market Information and Strategic Initiatives; Ohio Department of Job and Family Services, Bureau of Labor Market Information; and Wisconsin Department of Workforce Development.

A5. Computer Industry

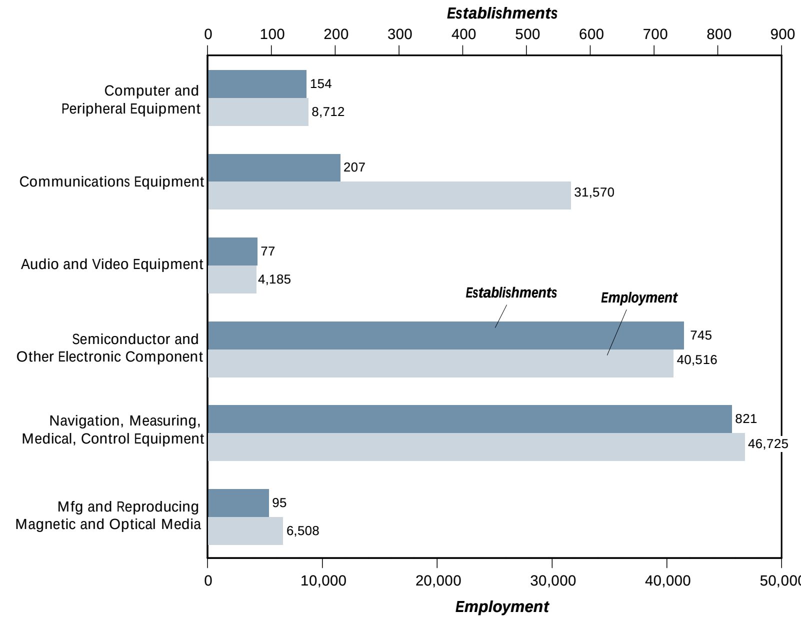
Computer Industry — Introduction

The computer and electronics product manufacturing sector employed approximately 138,000 people in the Midwest in 2002. The U.S. Census Bureau estimated approximately 2,000 manufacturing establishments in this industry in the Midwest.

The computer and electronic product manufacturing sector comprises six sectors that produce computers and related products; computer chips and other components; communications equipment; audio and visual electronic equipment; navigation, measuring, medical and control equipment; and manufacturing and reproducing magnetic and optical media.

Employment in these industries varies widely. As shown in Figure A5-1, the navigation, measuring, medical and control equipment industry is the largest sector in the Midwest with over 45,000 employees in 2002. The semiconductor and other electronic component sector employs more than 40,000 people in plants in the five-state region. The smallest employer — audio and video equipment manufacturing — provides about 4,000 jobs to people in the Midwest.

Figure A5–1.
Midwest establishments and employment in the computer and electronics manufacturing industry, 2002



Source: U.S. Census Bureau, EPCD, County Business Patterns.

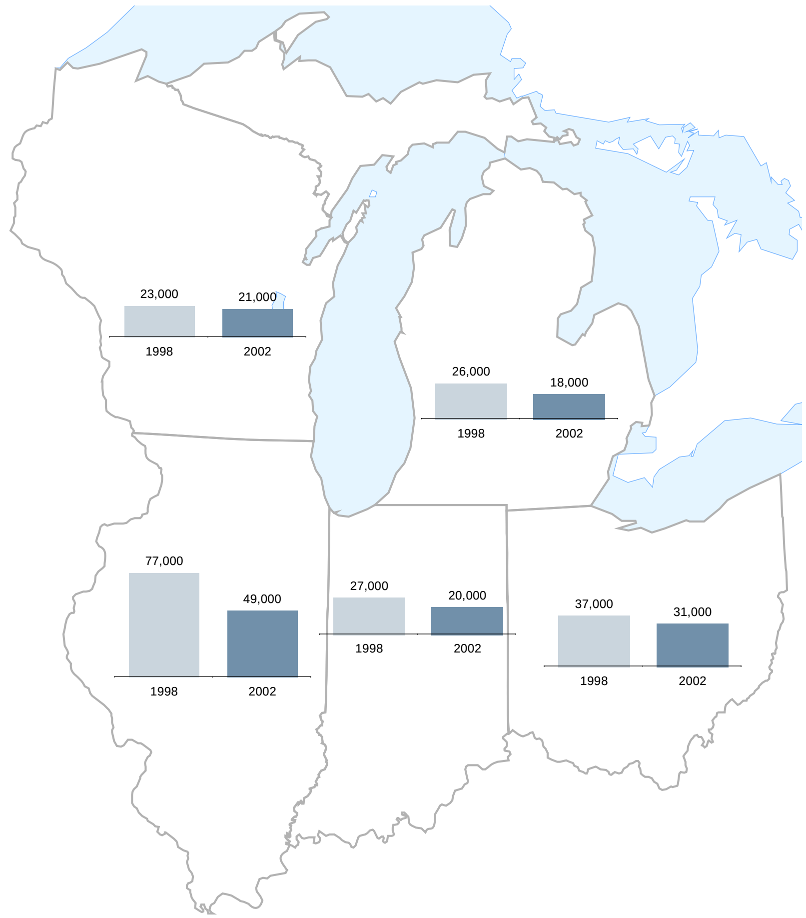
Computer Industry — Employment Trends

Employment in the computer and electronics products industry widely varies within the five-state region. While Michigan employed about 18,000 people in 2002, Illinois accounted for almost 50,000 jobs in the region for the same year. Ohio had over 30,000 jobs.

Due to overseas competition, outsourcing and increased automation, employment in the U.S. computer and electronic products manufacturing industry has been declining in recent years. Between 1998 and 2002, national employment in this industry dropped by 22 percent, or 380,000 jobs. During the same period, the Midwest lost 50,000 jobs in this industry. Illinois had the highest decline in employment in the Midwest in this industry, as that state lost almost 29,000 jobs lost in this period. Michigan lost 8,000 jobs and Ohio and Indiana both lost over 5,000 jobs in this sector.

Figure A5-2 shows employment in the computer manufacturing industry for 1998 and 2002 by state.

Figure A5–2.
Employment in the computer and electronics manufacturing industry



Source: U.S. Census Bureau, EPCD, County Business Patterns.

Computer Industry — Largest Employers

Dun & Bradstreet data list 13 computer and electronics products manufacturing establishments in the Midwest with at least 1,200 employees. Five of the large manufacturing establishments are located in Indiana and four are in Illinois. The remainder of the establishments are located in Ohio and Wisconsin.

Figure A5-3 shows the locations of the largest computer and electronics products manufacturing employers according to Dun & Bradstreet.

Figure A5–3. Computer and electronics manufacturing establishments with 1,200+ employees

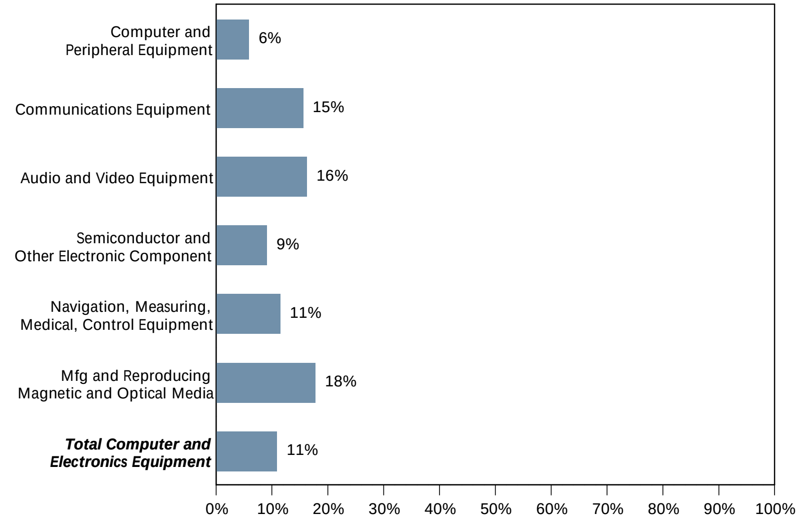
Source: Dun & Bradstreet Marketplace.

Computer Industry — Share of U.S. Employment

The Midwest represented about one-tenth of the national employment in the computer and electronics sector in 2002.

Employment in the manufacturing of magnetic and optical media in the Midwest was 18 percent of the national employment in this sector in 2002. The audio and video equipment manufacturing and communications equipments manufacturing in the five-state region each accounted for over 15 percent of the national employment in the corresponding industries in 2002. The Midwest's computer and peripheral equipment sector is small relative to the nation, as illustrated in Figure A5-4.

Figure A5–4.
Midwest share of U.S. computer and electronics manufacturing employment, 2002



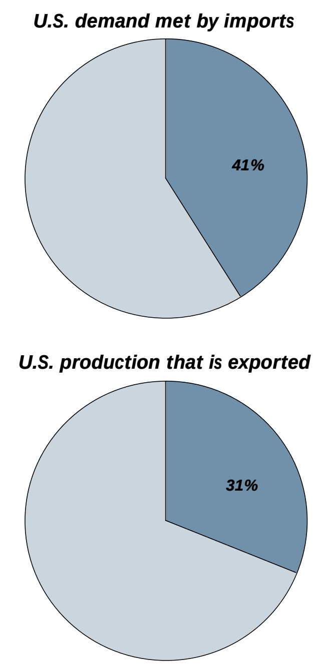
Source: U.S. Census Bureau, EPCD, County Business Patterns.

Computer Industry — Global Competition

Computer and electronics manufacturing is truly global — so much so that it is difficult to characterize many companies and their products as American or foreign. Many products are designed in one country, manufactured in another, and assembled in a third. For example, highly sensitive and sophisticated products such as semiconductors and computers are designed in the U.S., but it is likely that the various components are produced in different countries, then shipped to one site for final assembly. As illustrated in Figure CE-5, approximately 41 percent of U.S. demand in the computer and electronics sector in 2001 was met by imports and 31 percent of U.S. production was exported.

Rapid technological advances and intense price competition characterize the computer and electronic product manufacturing industry. Imports have almost entirely replaced domestic production for some portions of the U.S. consumer electronics industry.

Figure A5–5.
U.S. imports and exports of computer and electronic industry output, 2001



Source: U.S. Census Bureau, International Trade Administration, 2005.

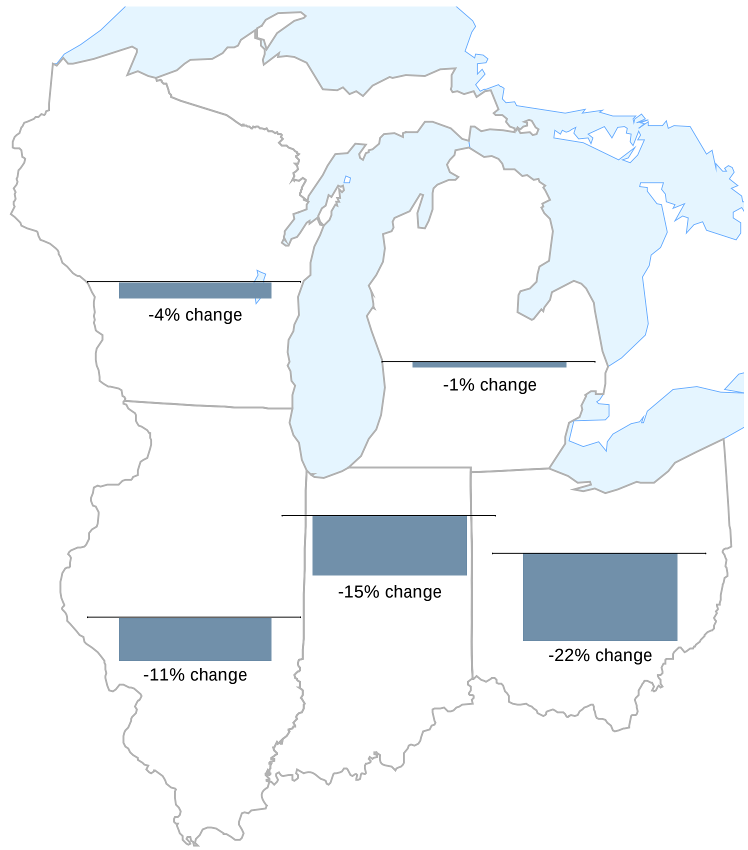
Computer Industry — Employment Forecasts

Although the output of the computer and electronics manufacturing industry is projected to continue to grow, because of continued productivity gains, employment in this sector is expected to decline. Employment is also likely to be affected by increases in imports of electronic and computer products and the outsourcing of certain positions in this industry.

National employment in the computer and electronic product manufacturing industry is expected to decline by 12 percent between 2002 and 2012. Various state sources forecast similar trends in the Midwest with regional job losses of just over 10 percent between 2002 and 2012. Job losses are predicted to be particularly severe in Ohio and Indiana for the computer and electronics manufacturing industry.

Figure A5-6 illustrates 2012 employment for each state in the computer and electronics manufacturing sector.

Figure A5–6.
Projected change in employment in the computer and electronics manufacturing industry, from 2002 to 2012



Source: Illinois Department of Employment Security, Economic Information & Analysis Division; Indiana Department of Workforce Development; Michigan Department of Labor and Economic Growth, Bureau of Labor Market Information and Strategic Initiatives; Ohio Department of Job and Family Services, Bureau of Labor Market Information; and Wisconsin Department of Workforce Development.

A6. Primary Metal Industry

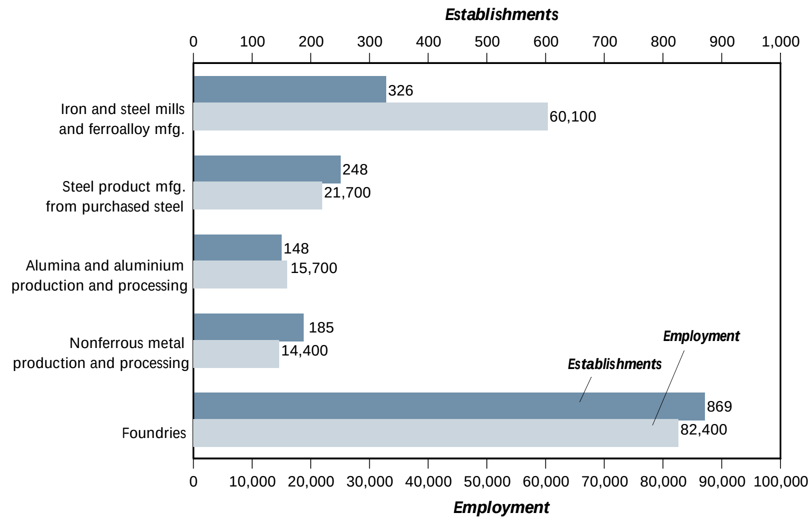
Primary Metal Industry — Introduction

The primary metals industry in the Midwest directly employs nearly 200,000 people and has multiple linkages to other sectors. In 2002, the U.S. Census Bureau counted 1,800 establishments within this industry in the five-state region.

As shown in Figure A6-1, five sectors comprise the primary metal industry. Sectors involving steel manufacturing account for the most jobs in the region. Many of these jobs involve making steel from iron ore and making castings from molten steel (classified as foundries if the establishment if the processing starts with refined steel). A smaller number of employees work in plants that make intermediate steel products (e.g., pipe, plate, wire) from purchased steel.

Aluminum manufacturing is also important in the Midwest, accounting for 15,700 jobs in 2002.

Figure A6–1.
Midwest establishments and employment in the primary metal manufacturing sector, 2002



Source: U.S. Census Bureau, EPCD, County Business Patterns.

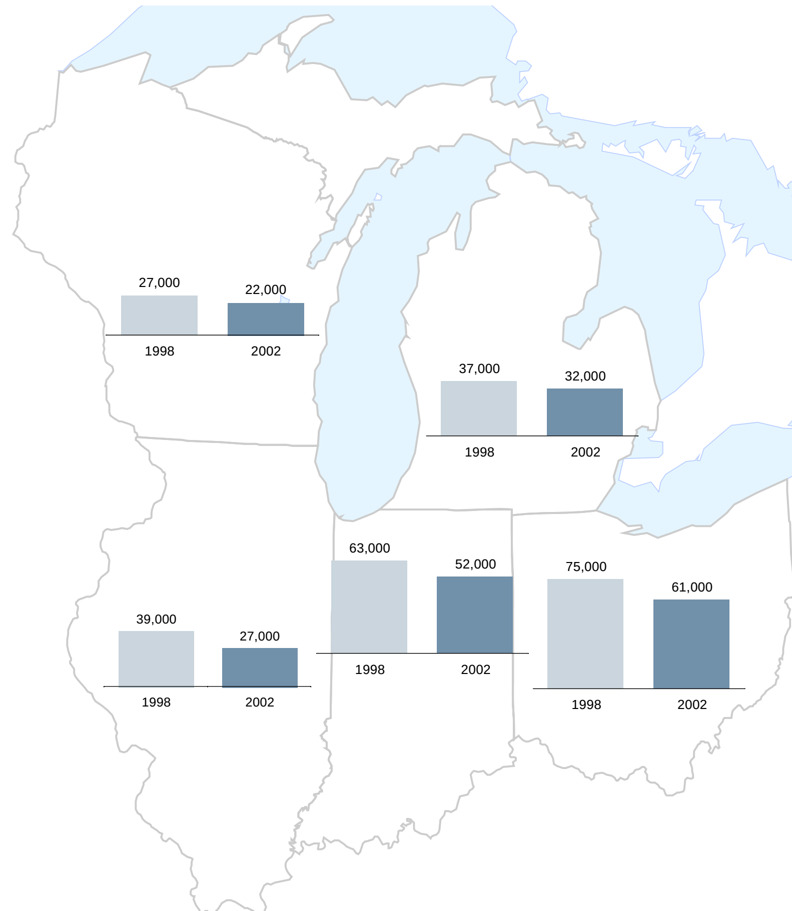
Primary Metal Industry — Employment Trends

The primary metal manufacturing industry is important to the local economies of each of the study region states. Based on 2002 U.S. Bureau of the Census County Business Patterns data, statewide employment ranges from 22,000 jobs in Wisconsin to 61,000 jobs in Ohio.

Employment in steel mills and other segments of the primary metal manufacturing industry has been declining throughout the country, and the Midwest has seen dramatic reductions in these jobs. Between 1998 and 2002, Indiana and Illinois both lost 11,000 jobs in the primary metal industry and Ohio lost 14,000 jobs. Many of these jobs have been lost due to increasing pressures on this industry from foreign competition and the productivity gains required to remain competitive. As output per labor hour has substantially increased, the total labor needs in the sector have decreased.

Figure A6-2 shows County Business Patterns data for 1998 and 2002 by state.

Figure A6–2.
Employment in the primary metal industry



Source: U.S. Census Bureau, EPCD, County Business Patterns.

Primary Metal Industry — Largest Employers

Based on Dun & Bradstreet data, there are 19 primary metal manufacturing establishments in the Midwest with at least 1,000 employees. One large employer is located in Michigan, three are in Wisconsin and three are in Illinois. The balance are located in Indiana and Ohio.

Figure A6-3 shows the locations of the largest primary metal manufacturing employers according to Dun & Bradstreet.

Figure A6–3. Primary metal manufacturing establishments with 1,000+ employees

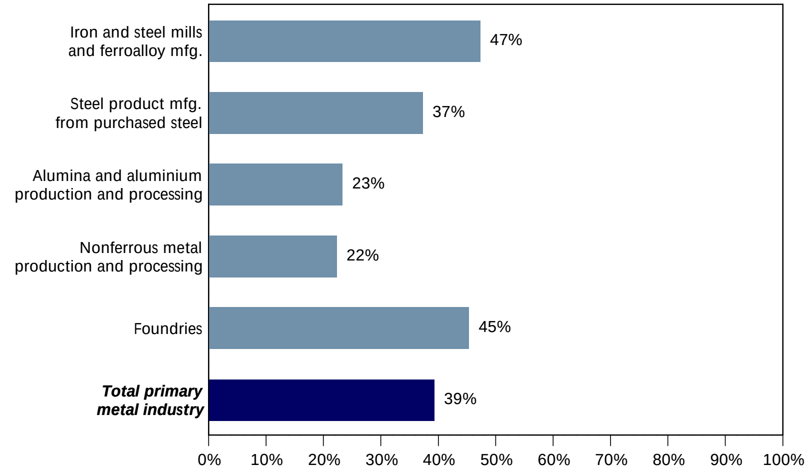
Source: Dun & Bradstreet Marketplace.

Primary Metal Industry — Share of U.S. Employment

A large share of U.S. primary metal production in based in the Midwest. The five-state region accounts for nearly one-half of national employment in steel mills and foundries, and more than one-third of the nation's jobs in steel product manufacturing from purchased steel.

In total, 39 percent of U.S. employment in the primary metal industry in 2002 was in the Midwest, as illustrated in Figure A6-4.

Figure A6–4.
Midwest share of U.S. primary metals manufacturing employment, 2002



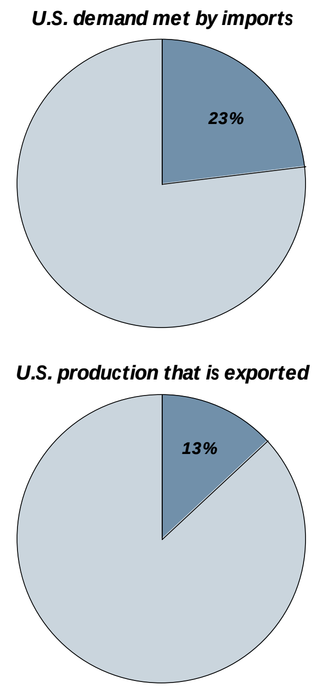
Source: U.S. Census Bureau, EPCD, County Business Patterns.

Primary Metal Industry — Global Competition

Supply and demand forces affecting the Midwest primary metal industry are global. In 2001, 23 percent of U.S. demand for products in this industry was met by imports and 13 percent of U.S. output was exported.

The steel industry provides one example of this dynamic. U.S. exports and imports of steel are affected by factors including alleged dumping of steel products in the U.S. by foreign producers, periodic imposition of U.S. tariffs on steel imports, China's rapidly-growing demand for steel, changes in relative production costs throughout the world, and current exchange rates. Demand for steel, as well as total U.S. steel production, have significantly increased, though the U.S. remains a net importer of steel. Steel prices have risen in 2004 and 2005, and U.S. steel production is nearing capacity.

Figure A6–5.
U.S. imports and exports of primary metals manufacturing output, 2001



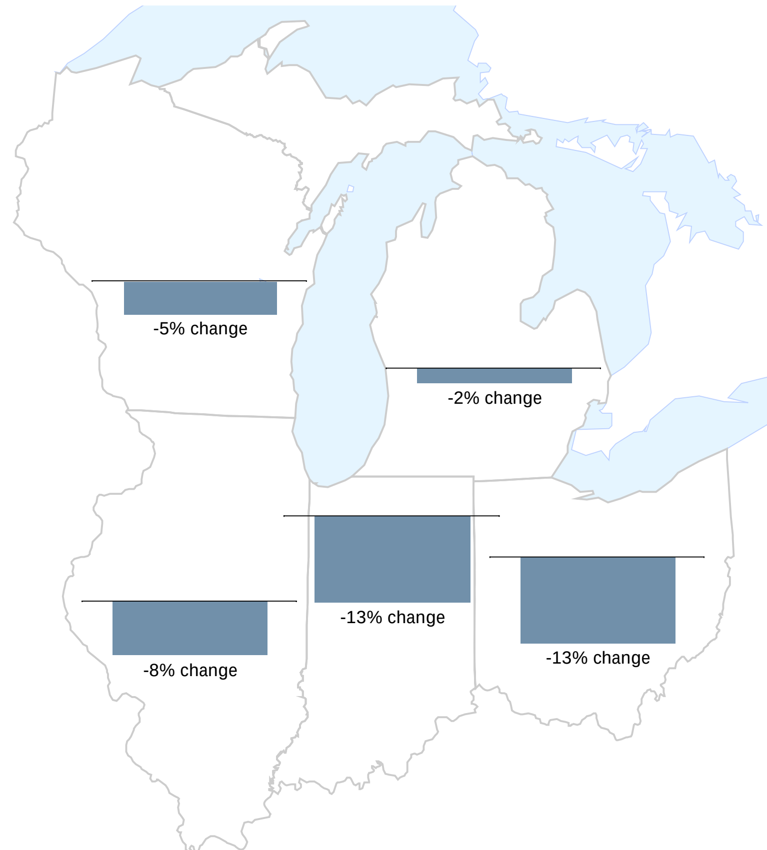
Source: U.S. Census Bureau, International Trade Administration, 2005.

Primary Metal Industry — Employment Forecasts

Even though demand for primary metal products will continue to be strong in the future, this expansion will not lead to job creation as worker productivity is expected to increase. The U.S. Bureau of Labor Statistics forecasts a 33 percent growth in value of national output between 2002 and 2012, but a 3 percent decline in U.S. primary metals employment over the same period.

Forecasts obtained from each state project continued declines in employment in the primary metal industry. By 2012, employment in the primary metal industry in the five-state region is expected to decrease by approximately 10 percent. Figure A6-6 shows the percent change in employment between 2002 and 2012 expected by each state.

Figure A6–6.
Projected percent change in employment in the primary metal industry, from 2002 to 2012



Source: Illinois Department of Employment Security, Economic Information & Analysis Division; Indiana Department of Workforce Development; Michigan Department of Labor and Economic Growth, Bureau of Labor Market Information and Strategic Initiatives; Ohio Department of Job and Family Services, Bureau of Labor Market Information; and Wisconsin Department of Workforce Development.

A7. Fabricated Metal Industry

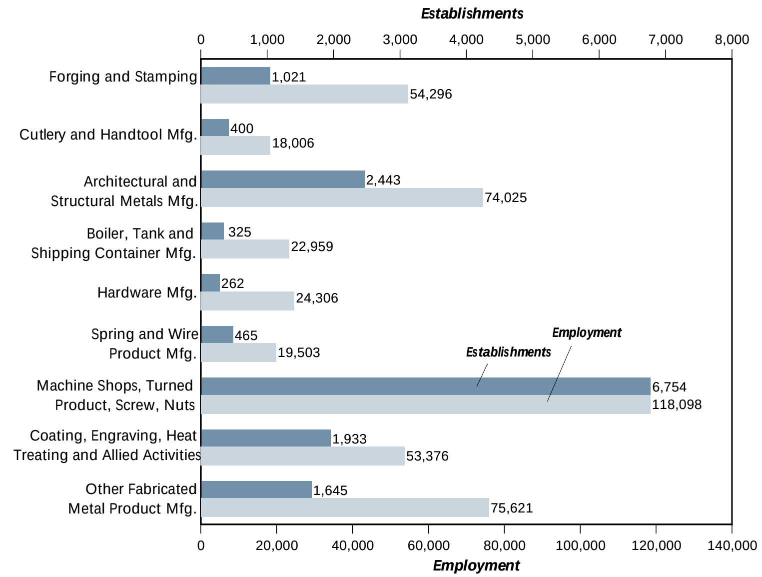
Fabricated Metal Industry — Introduction

The fabricated metal products industry in the Midwest directly employs over 460,000 people, is a major purchaser of primary metals, and creates important inputs for related industries. In 2002, the U.S. Census Bureau counted about 15,000 establishments in this industry in the five-state region.

The fabricated metal products industry includes plants that forge and shape metal into a broad range of business and consumer products. As shown in Figure A7-1, machine shops and related companies represent the largest number of establishments and employees in the Midwest's fabricated metals industry. Firms involved with plate work, fabricated structural work and ornamental and architectural metal products are the second largest employer in this sector.

Cutlery and hand tools manufacturing is the smallest sector, employing just 18,000 people in the five-state area.

Figure A7–1.
Midwest establishments and employment in the fabricated metal industry, 2002



Source: U.S. Census Bureau, EPCD, County Business Patterns.

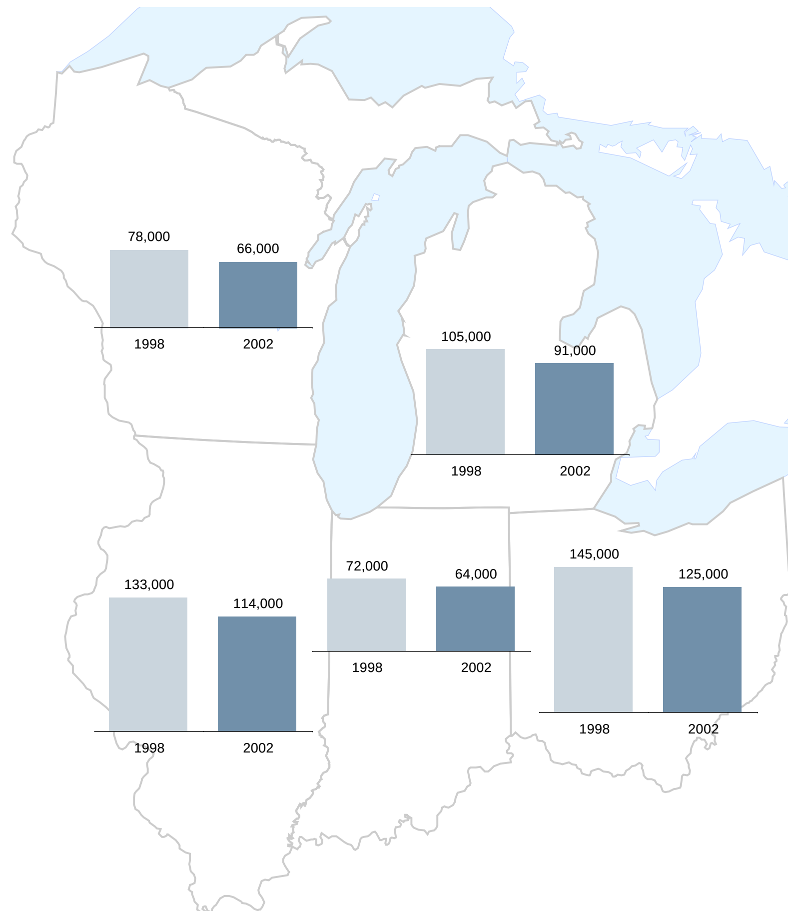
Fabricated Metal Industry — Employment Trends

U.S. Bureau of Census employment estimates for 2002 placed Ohio, Illinois and Michigan as leading states for fabricated metals manufacturing.

The Midwest region lost 73,000 fabricated metals jobs between 1998 and 2002. Ohio tops the list with 20,600 jobs lost during this period. Each of the other Midwest states had jobs losses in this sector during this period.

Figure A7-2 shows Midwest employment in the fabricated metal industry for 1998 and 2002.

Figure A7–2.
Employment in the fabricated metal industry



Source: U.S. Census Bureau, EPCD, County Business Patterns.

Fabricated Metal Industry — Largest Employers

Based on Dun & Bradstreet data, there are 15 fabricated metal manufacturing establishments in the Midwest with at least 800 employees. As is shown in Figure A7-3, five large employers are located in Ohio and five are in Wisconsin.

Figure A7–3.
Fabricated metal establishments with 800+ employees

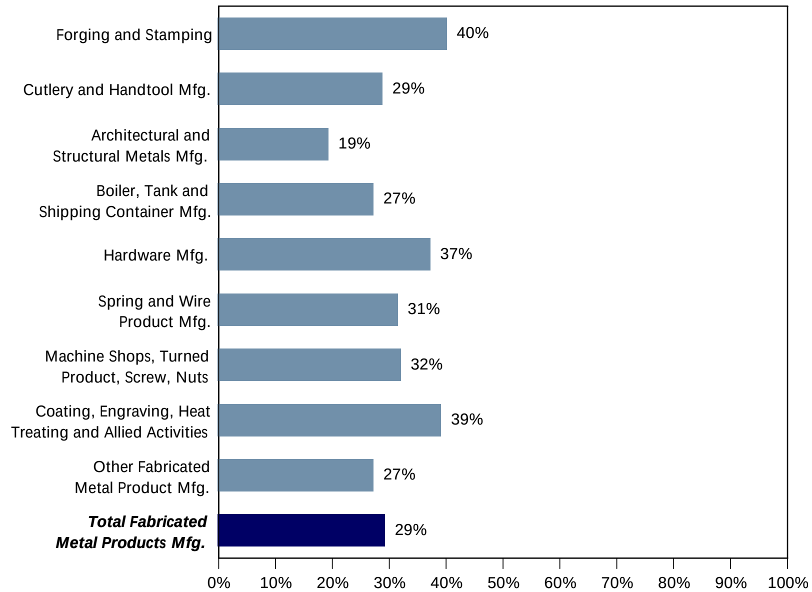
Source: Dun & Bradstreet Marketplace.

Fabricated Metal Sector — Share of U.S. Employment

A large share of U.S. fabricated metal production is based in the Midwest. The five-state region accounts for nearly 30 percent of domestic employment in the fabricated metal manufacturing industry, as illustrated in Figure A7-4.

The region accounts for about 40 percent of the nation's workers in metal forging and stamping as well as in metal coating, engraving and heat treating. Architectural and structural metals manufacturing in the Midwest accounts for about 20 percent of all the nation's employees in this sector. Each of the other six sectors in the Midwest in this industry account for over one-quarter of U.S. workers.

Figure A7–4.
Midwest share of U.S. fabricated metal employment, 2002

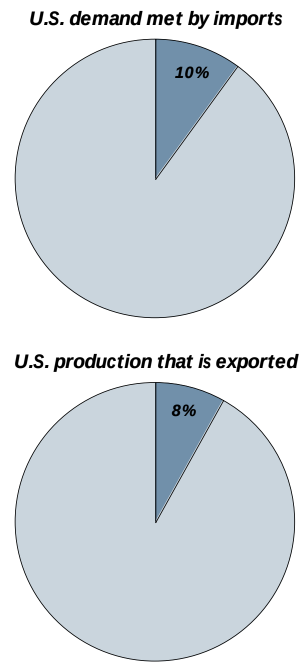


Source: U.S. Census Bureau, EPCD, County Business Patterns.

Fabricated Metal Industry — Global Competition

Although the U.S. fabricated metal manufacturing industry faces competition from low-cost overseas suppliers, a relatively small portion of total U.S. output is imported or exported. In 2001, only 10 percent of U.S. demand for products in this industry was met by imports, while 13 percent of U.S. output was exported.

Figure A7–5.
U.S. imports and exports of fabricated metal output, 2001



Source: U.S. Census Bureau, International Trade Administration, 2005.

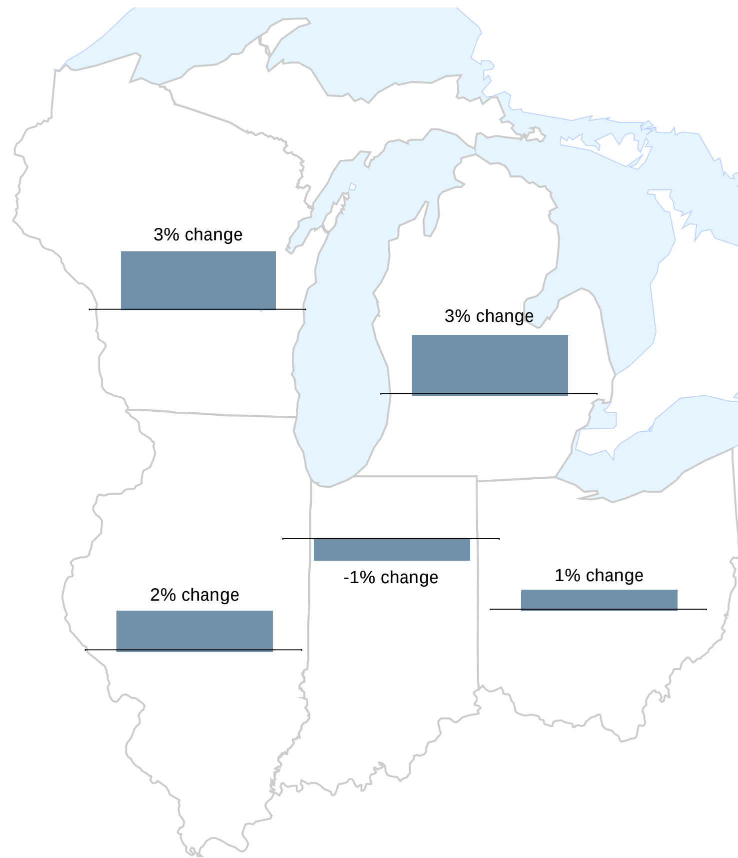
Fabricated Metal Industry — Employment Forecasts

Demand for products from the fabricated metals industry is likely to increase between now and 2012, as is employment in this industry. The U.S. Bureau of Labor Statistics forecasts a 6.3 percent increase in U.S. employment in this industry between 2002 and 2012.

By 2012, employment in the five-state region is expected to increase by approximately 2 percent. Job growth is expected in this sector in each state except Indiana.

Figure A7-6 shows the change in employment between 2002 and 2012 expected by each state.

Figure A7–6.
Projected change in employment in the fabricated metal industry, from 2002 to 2012



Source: Illinois Department of Employment Security, Economic Information & Analysis Division; Indiana Department of Workforce Development; Michigan Department of Labor and Economic Growth, Bureau of Labor Market Information and Strategic Initiatives; Ohio Department of Job and Family Services, Bureau of Labor Market Information; and Wisconsin Department of Workforce Development.

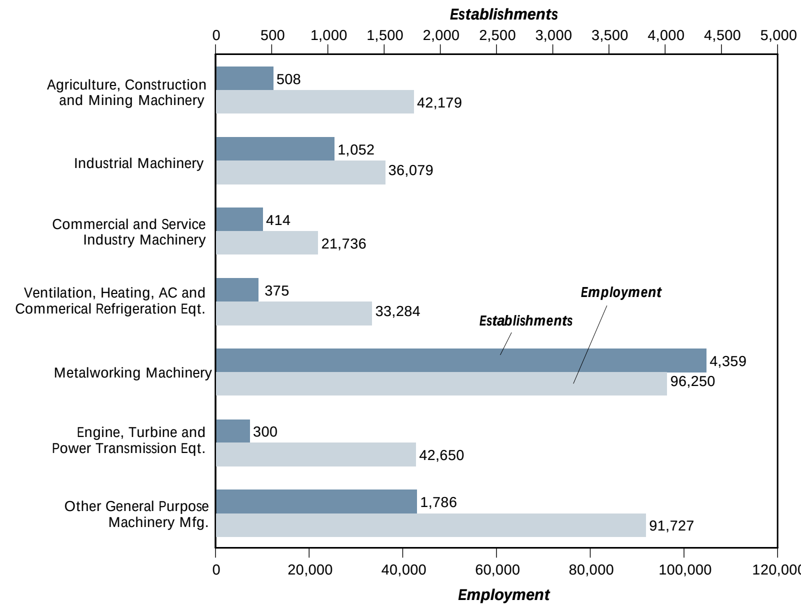
A8. Machine Industry

Machinery Industry — Introduction

The manufacture of machinery in the U.S. involves over a million workers in 30,000 establishments. U.S. Census Bureau County Business Patterns data estimate that over 360,000 of these employees worked in the five-state region in 2002.

The machinery manufacturing industry encompasses a number of diverse subsectors. In 2002, the metalworking machinery sector and the general purpose machinery sector employed the most people in the Midwest, each employing more than 90,000 workers in that year (see Figure A8-1). The manufacture of agriculture, construction and mining machinery, and engine, turbine and power transmission equipment manufacturing both employed over 40,000 employees in 2002. The commercial and service industry machinery manufacturing sector employs the fewest workers within this sector, providing 20,000 jobs to the five-state region.

Figure A8–1.
Midwest establishments and employment in the machinery manufacturing industry, 2002



Source: U.S. Census Bureau, EPCD, County Business Patterns.

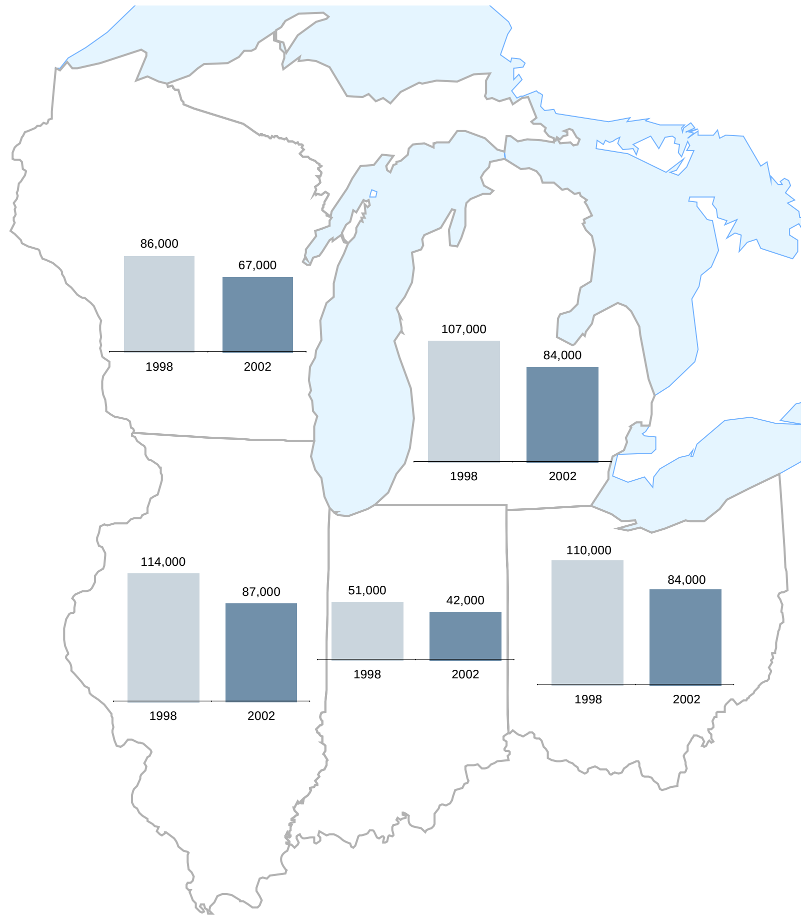
Machinery Industry — Employment Trends

According to U.S. Census Bureau County Business Pattern data for 2002, employment in the machinery manufacturing industry in the five-state region ranges from 44,000 employees in Indiana to about 87,000 employees in Illinois.

Employment in the machinery manufacturing sector in the Midwest declined significantly between 1998 and 2002. Each state lost employment in the machinery manufacturing sector between 1998 and 2002. About 25,000 jobs were lost in Ohio, and a similar number were lost in Illinois and Michigan. In total, the Midwest lost over 100,000 jobs in the machinery industry during this period.

Figure A8-2 shows state-by-state employment in the machinery industry for 1998 and 2002.

Figure A8–2.
Employment in the machinery manufacturing industry



Source: U.S. Census Bureau, EPCD, County Business Patterns.

Machinery Industry — Largest Employers

Dun & Bradstreet identifies 14 machinery manufacturing establishments in the Midwest with at least 2,000 employees. Six of the large manufacturing establishments are located in Illinois and four are based in Ohio. The rest of the large employers are in Wisconsin and Michigan.

Figure A8-3 shows the locations of the largest machinery manufacturing employers according to Dun & Bradstreet.

Figure A8–3.
Machinery manufacturing establishments with 2,000+ employees

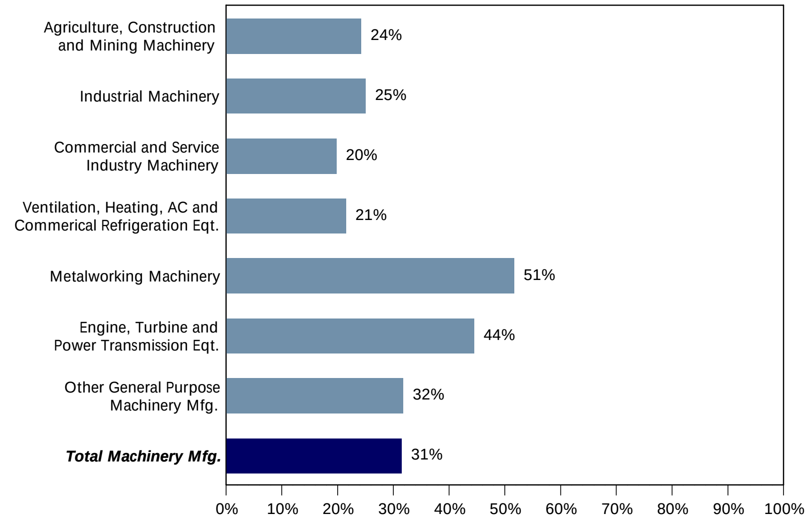
Source: Dun & Bradstreet Marketplace.

Machinery Industry — Share of U.S. Employment

The Midwest accounts for almost one-third of national employment in the machinery manufacturing sector.

Figure A8-4 shows the Midwest's share of U.S. machinery manufacturing employment. The five-state region accounts for over half of the national employment in the metalworking machinery industry. Engine, turbine and power transmission manufacturers in the Midwest employ 44 percent of all U.S. workers employed in that industry.

Figure A8–4.
Midwest share of U.S. machinery manufacturing employment, 2002



Source: U.S. Census Bureau, EPCD, County Business Patterns.

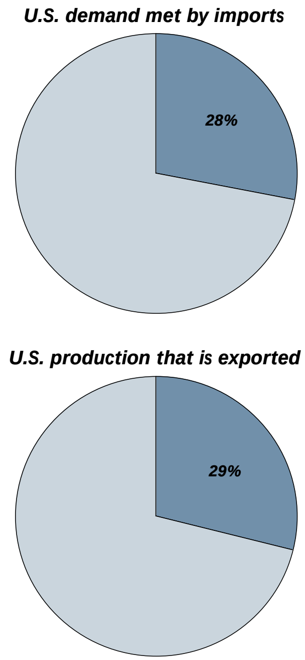
Machinery Industry — Global Competition

Once typically local or regional in scale, competition in the machinery manufacturing industry is now global. In 2001, 28 percent of the U.S. demand in this industry was met by imports and 29 percent of the production was exported.

Demand for machinery depends strongly on the health of the overall U.S. economy. Specific industries, such as the construction industry, play a critical role in determining the health of the machinery manufacture industry. Because of projected growth in the construction industry, as well as other heavy machinery-use industries, demand for machinery is expected to increase through 2012.

Global competition from European and Asian companies is intensifying. As a consequence, U.S. factories are being taken to Canada, China, Mexico and other countries where cheap labor is abundant. These factors, and others, such as oil and gas prices and commodity costs (particularly the cost of steel) will continue to affect the global machinery market in the future.

Figure A8–5.
U.S. imports and exports of machinery manufacturing output, 2001



Source: U.S. Census Bureau, International Trade Administration, 2005.

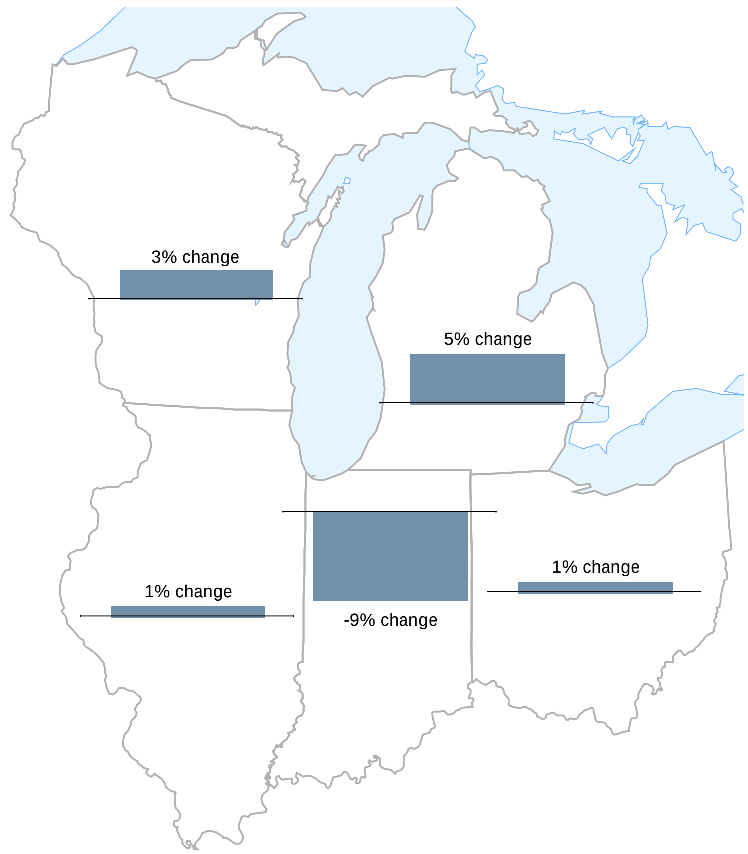
Machinery Industry — Employment Forecasts

Although machinery manufacturing is expected to continue to expand, productivity gains will keep this growth from translating into sizeable job gains, especially in the Midwest. Combining Midwestern states' employment projections for this sector, there will be modest overall job growth between 2002 and 2012.

In fact, state sources forecast employment in the machinery industry to remain stable in the five-state region between 2002 to 2012. While Indiana expects significant job losses, Illinois, Michigan and Wisconsin all project employment gains in the machinery sector.

Figure A8-6 shows the expected change in employment between 2002 and 2012.

Figure A8–6.
Projected change in employment
in the machinery manufacturing industry, from 2002 to 2012



Source: Illinois Department of Employment Security, Economic Information & Analysis Division; Indiana Department of Workforce Development; Michigan Department of Labor and Economic Growth, Bureau of Labor Market Information and Strategic Initiatives; Ohio Department of Job and Family Services, Bureau of Labor Market Information; and Wisconsin Department of Workforce Development.

A9. Transportation Equipment

Transportation Equipment — Introduction

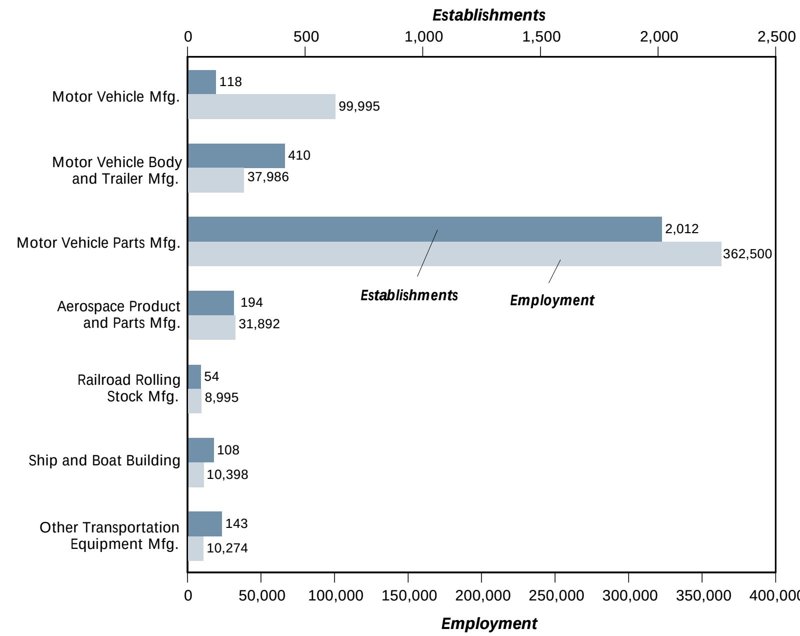
Industries in the transportation equipment manufacturing sector produce equipment for transporting people and goods. Although transportation equipment is a type of machinery, the federal government separately examines the transportation equipment sector because of its significance to the U.S. economy.

The transportation equipment manufacturing industry in the U.S. employed approximately 1.6 million people in 2002, of which 550,000 were in the five-state region. The U.S. Census Bureau estimates more than 3,000 establishments in this industry in the Midwest.

The transportation sector consists of industry groups from all modes of transport, as is shown in Figure A9-1. Within the transportation industry, the motor vehicle parts manufacturing subsector accounts for the largest number of jobs in the region — approximately 360,000 workers in 2002. Motor vehicle manufacturing, which is largely assembly, employed about 100,000 people in the Midwest in 2002.

Relatively little airplane, railroad and ship manufacturing takes place in the Midwest.

Figure A9–1.
Midwest establishments and employment in transportation equipment manufacturing sectors, 2002



Source: U.S. Census Bureau, EPCD, County Business Patterns.

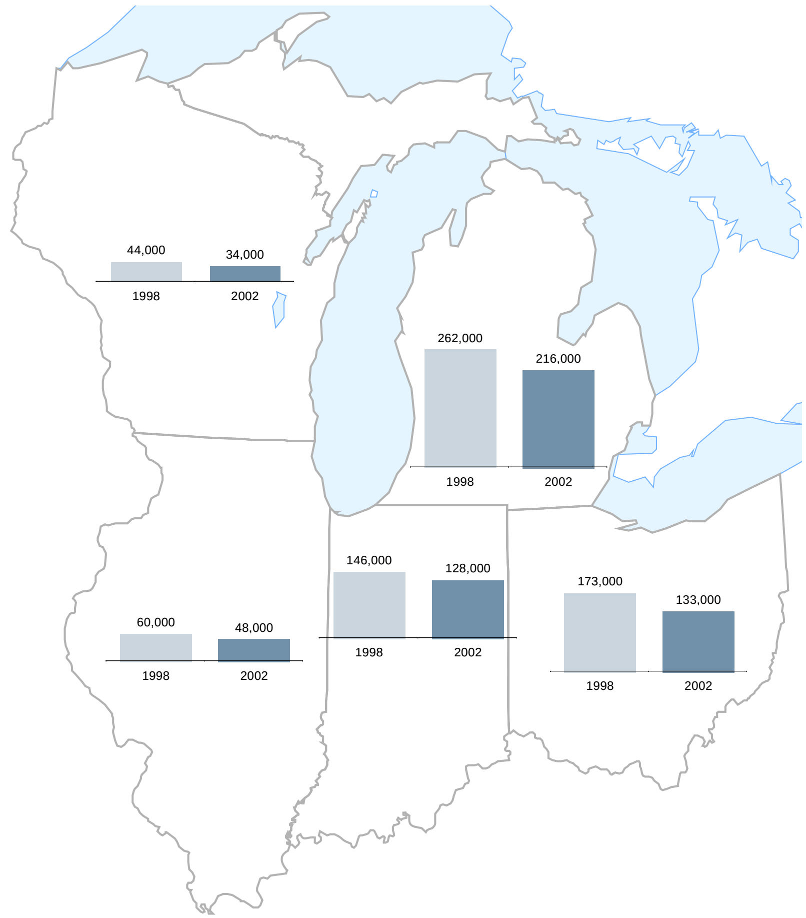
Transportation Equipment — Employment Trends

In spite of increases in demand for transportation equipment, employment in this industry has substantially declined. Between 1998 and 2002, jobs in the industry decreased by 300,000 nationally. The Midwest lost 125,000 jobs during the same time period, about 20 percent of the employment in 1998.

According to U.S. Census Bureau, state employment in the Midwest ranged from 34,000 employees in Wisconsin to over 215,000 employees in Michigan in 2002. However, more than 40,000 jobs were lost in both Ohio and Michigan between 1998 and 2002.

Figure A9-2 shows County Business Patterns jobs data for 1998 and 2002 by state.

Figure A9–2.
Employment in the transportation equipment manufacturing industry



Source: U.S. Census Bureau, EPCD, County Business Patterns.

Transportation Equipment — Largest Employers

The Midwest is home to many of the largest transportation equipment manufacturing establishments in the nation. Data from Dun & Bradstreet show 15 establishments with at least 3,000 employees. Almost half of these facilities are located in Michigan and another four are located in Indiana.

Figure A9-3 shows the locations of the largest transportation equipment manufacturing establishments according to Dun & Bradstreet.

Figure A9–3.
Transportation equipment manufacturing establishments with 3,000+ employees

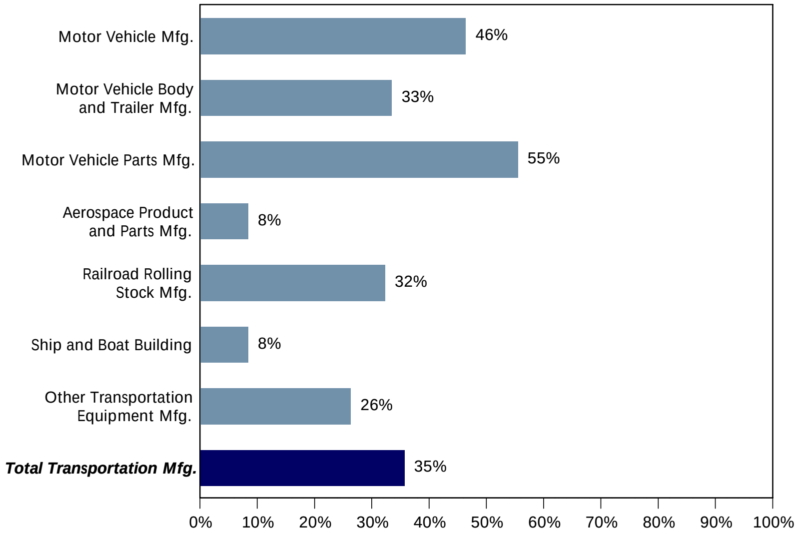
Source: Dun & Bradstreet Marketplace.

Transportation Equipment — Share of U.S. Employment

According to 2002 U.S. Census Bureau County Business Patterns data, Michigan is the largest employer of transportation equipment workers in the nation, followed by Ohio. The Midwest accounted for more than one-third of employees in this industry in the U.S. in 2002.

The five-state region accounts for about 55 percent of all motor vehicle parts manufacturing workers and more than 45 percent of motor vehicle manufacturing jobs in the United States, as is illustrated in Figure A9-4. Eight percent of all national aerospace products and parts manufacturing and ship building manufacturing jobs are in the Midwest. The rest of the industries in this sector have employment ranging from 20 to 35 percent of all national employment in the corresponding industries.

Figure A9–4.
Midwest share of U.S. transportation equipment manufacturing employment, 2002



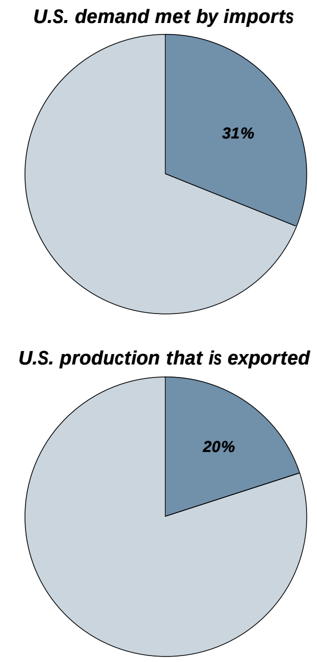
Source: U.S. Census Bureau, EPCD, County Business Patterns.

Transportation Equipment — Global Competition

The transportation equipment industry is global. In 2001, 31 percent of the U.S. demand in this industry was met by imports while 20 percent of U.S. production was exported, as shown in Figure A9-5. These data include vehicles, vehicle parts, aviation equipment, ships and boats, and railroad equipment.

The automobile industry presents an example of global competition. U.S. automakers' response has been a continued focus on productivity gains and control of labor costs. In June 2005, General Motors announced layoffs of 25,000 workers within the United States by 2008.

Figure A9–5.
U.S. imports and exports of transportation equipment manufacturing output, 2001



Source: U.S. Census Bureau, International Trade Administration, 2005.

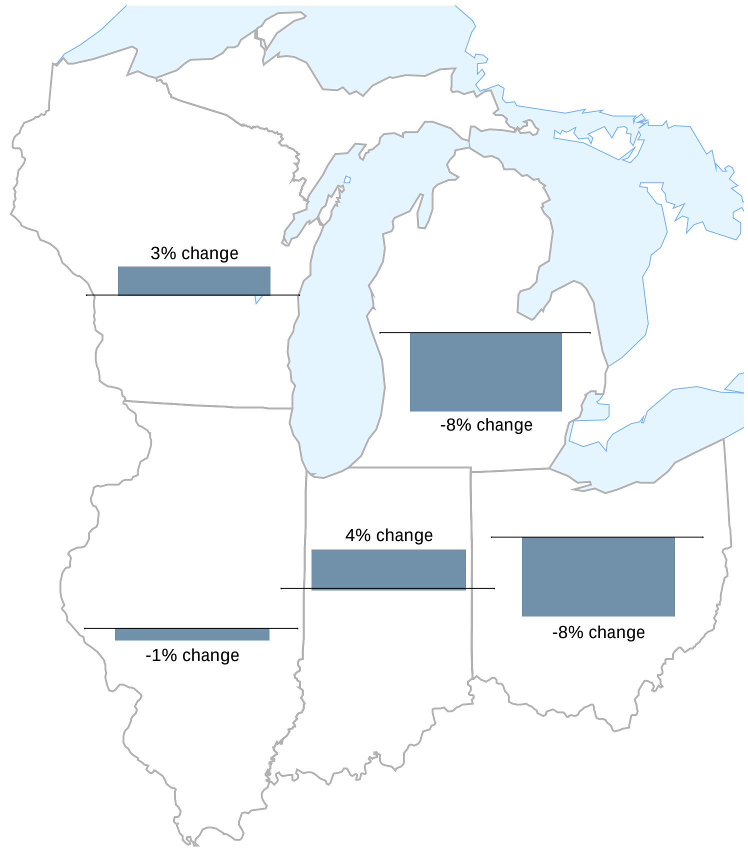
Transportation Equipment — Employment Forecasts

Employment in the transportation equipment sector is expected to decline between 2002 and 2012. Projections for 2012 by Midwestern states suggest a regional job loss of approximately 5 percent in this industry. Competition from outside the U.S. and increased worker productivity because of automation are the main reasons for the job losses.

The State of Michigan predicts the largest job losses in its state – a decline of about 10 percent between 2002 and 2012. Ohio is predicted to lose a similar proportion of jobs by 2012. Indiana and Wisconsin, however, forecast modest increases in transportation equipment manufacturing employment during this time frame.

Figure A9-6 illustrates the projected change in employment the Midwest region between 2002 and 2012.

Figure A9–6.
Projected change in employment in the transportation equipment manufacturing industry, from 2002 to 2012



Source: Illinois Department of Employment Security, Economic Information & Analysis Division; Indiana Department of Workforce Development; Michigan Department of Labor and Economic Growth, Bureau of Labor Market Information and Strategic Initiatives; Ohio Department of Job and Family Services, Bureau of Labor Market Information; and Wisconsin Department of Workforce Development.

A10. Coal Mining Industry

Coal Mining Industry — Introduction

Coal remains the dominant fuel source for electric power generation across the U.S., and in the Midwest in particular. In 2003, coal-fired plants produced about 51 percent of the nation's electricity and nearly 70 percent of the electricity generated in the LADCO region.

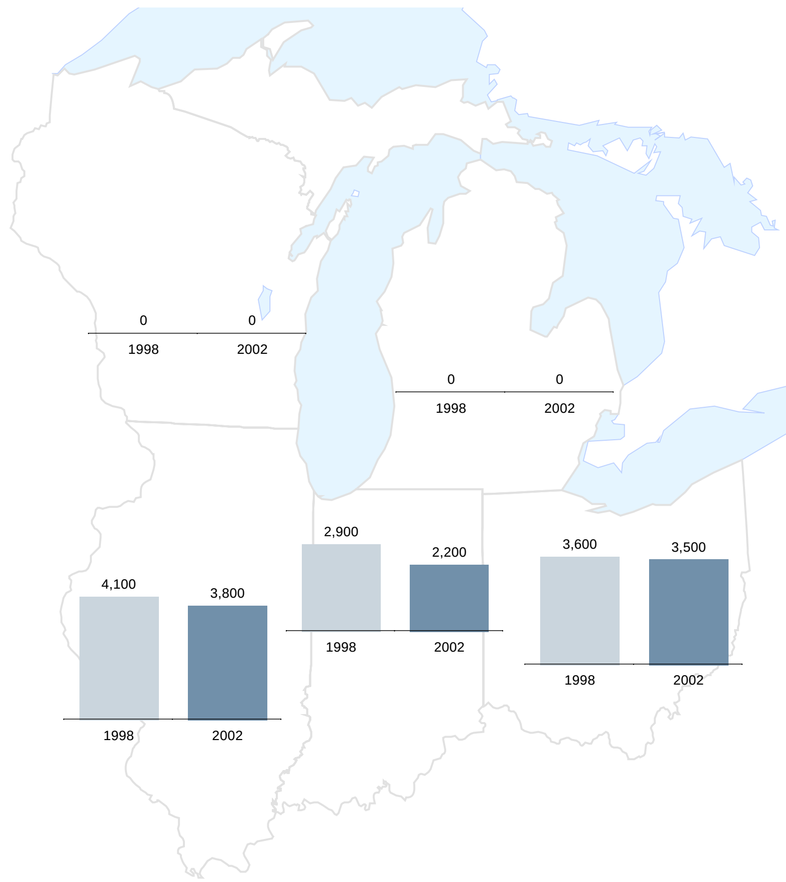
In 2002, the U.S. Census Bureau counted approximately 130 coal mining establishments in the Midwest region. These establishments directly employed about 9,500 people in the coal mines in 2002. In the same year, the Energy Information Administration estimated 8,800 coal mine workers in the Midwest.

Increased productivity resulting from technological advances in mining operations and consolidation have caused a significant decline in the number of mining jobs in the nation. Competition from low cost, low-sulfur Western coal, primarily from Wyoming's Powder River Basin, has also led to declines in coal mine production and employment in other parts of the U.S. Between 1998 and 2002, the Midwest lost 10 percent of its coal mining jobs (about 1,100 jobs). Indiana lost about 600 jobs in this sector while Wisconsin and Ohio lost 300 and 120 coal mining jobs, respectively, between 1998 and 2002.

Michigan lost 19 employees and its only coal mine between 1998 and 2002. Wisconsin also no longer has any active coal mines.

Figure A10-1 represents coal mine employment in 1998 and 2002 in the five-state region.

Figure A10–1.
Employment in the Coal Mining industry



Source: U.S. Census Bureau, EPCD, County Business Patterns.

Coal Mining Industry — Largest Employers

There were approximately 1,200 coal mining establishments in the U.S. in 2002. Dun & Bradstreet marketplace data indicates 18 coal mining establishments in the Midwest with over 100 employees. Seven of the large coal mining establishments are located in Illinois, six are located in Indiana and five establishments are based in Ohio.

Figure A10-2 shows locations of the largest establishments in the Midwest based on Dun & Bradstreet information.

Figure A10–2.
Coal mining establishments with 100+ employees

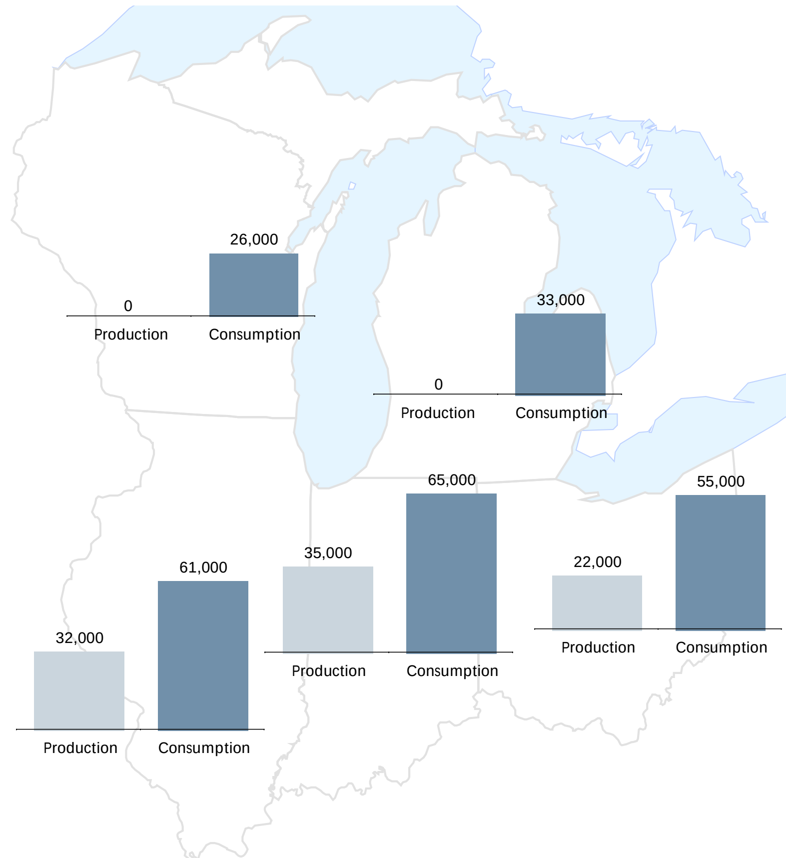
Source: Dun & Bradstreet Marketplace.

Coal Mining Industry — Production and Consumption

U.S. coal production in 2003 amounted to 1.07 billion tons according to the Energy Information Administration. During the same year, the Midwest produced about 89 million tons of coal. Midwest coal consumption during 2003 was estimated at 240 million short tons. The electric power sector including electric utilities and independent power producers accounted for almost 90 percent of all coal consumed in the Midwest in 2003. Other coal consuming sectors such as coking coal, residential and commercial sectors and other industrial sectors rounded out the rest of the coal used in the region.

Indiana is the largest producer and consumer of coal in the Midwest. Michigan and Wisconsin had no coal production but they accounted for 33 million short tons and 26 million short tons of coal consumed, respectively, in 2003. Figure A10-3 illustrates the production and consumption of coal in the five-state region in 2003.

Figure A10–3.
Coal production and consumption in the Midwest, 2003 (1,000 short tons)



Source: Energy Information Administration, Department of Energy.

Based on EIA data, about 81 percent of the coal originating in the Midwest is consumed within the region. Approximately 46 percent of the coal produced in Illinois is consumed within the state and 19 percent is consumed by the other four states in the Midwest. The remainder of the coal produced in Illinois goes to states outside of the study region. Almost 93 percent of the coal produced in Indiana is consumed within the five-state region and 83 percent of the coal produced in Ohio is consumed within the region.

Figure A10-4 shows coal consumption within and outside of the five-state LADCO region by state of origin in 2003.

Figure A10–4.
Distribution of Coal by State of Origin and Destination, 2003 (1,000 short tons)

	State of Origin			
Destination	***Illinois***	***Indiana***	***Ohio***	***Region***
Illinois	14,483	566	0	15,049
Indiana	5,273	31,631	97	37,001
Michigan	51	0	366	147
Ohio	219	315	17,652	18,186
Wisconsin	518	428	1	947
Total LADCO	***20,544***	***32,940***	***18,116***	***71,600***
Total Production	***31,751***	***35,350***	***21,770***	***88,871***
Percent to LADCO	***65%***	***93%***	***83%***	***81%***

Note: Midwest states include: Illinois, Indiana, Ohio, Michigan and Wisconsin.
Source: Energy Information Administration, 2005.

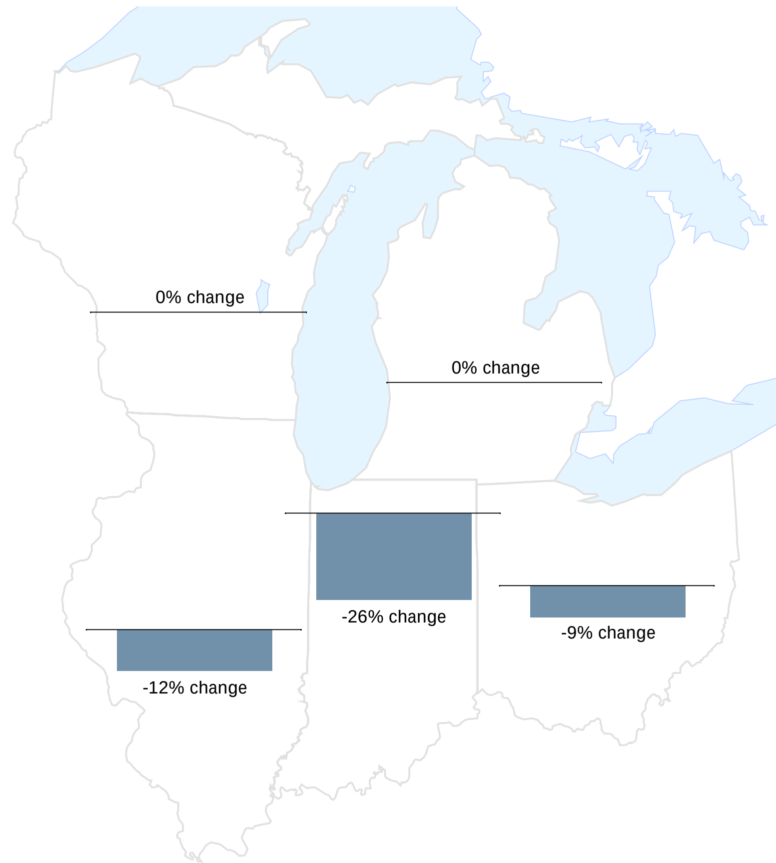
Coal Mining Industry — Employment Projections

Across the U.S. as a whole, the coal mining industry is expected to increase its output in the next few years. However, coal mining employment is estimated to continue to decline through 2012.

The U.S. Bureau of Labor Statistics indicates loss of 23,000 coal mining jobs in the U.S. between 2002 and 2012. Various state sources predict the Midwest to lose about 14 percent of its regional coal mining employment during this ten-year period.

Figure A10-5 shows the change in employment between 2002 and 2012 based on each state's individual projections.

Figure A10–5.
Percent change in employment
in the coal mining industry, from 2002 to 2012



Source: Illinois Department of Employment Security, Economic Information & Analysis Division; Indiana Department of Workforce Development; Michigan Department of Labor and Economic Growth, Bureau of Labor Market Information and Strategic Initiatives; Ohio Department of Job and Family Services, Bureau of Labor Market Information; and Wisconsin Department of Workforce Development.

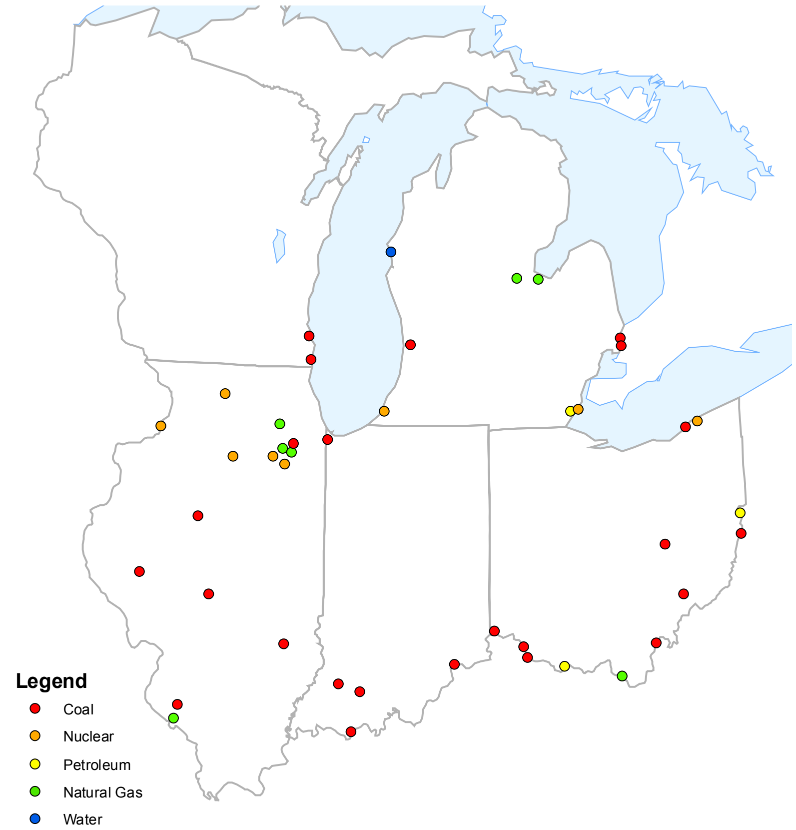
A11. Electric Power Industry

Electric Power Industry — Introduction

There are about 750 power-generating plants now operating in the Midwest. Of these plants, 43 have a capacity of at least 1,200 megawatts (MW). These 43 plants have a combined capacity of nearly 80,000 MW, or about half of all the electric power generating capacity in the Midwest.

Of the plants with a capacity of at least 1,200 MW, there are 15 in Illinois, 12 in Ohio, nine in Michigan, five in Indiana, and two in Wisconsin. Figure A11-1 shows the locations of the largest power-generating plants in the Midwest.

Figure A11-1.
Electric power-generating power plants in the Midwest with capacity of 1,200 MW or greater



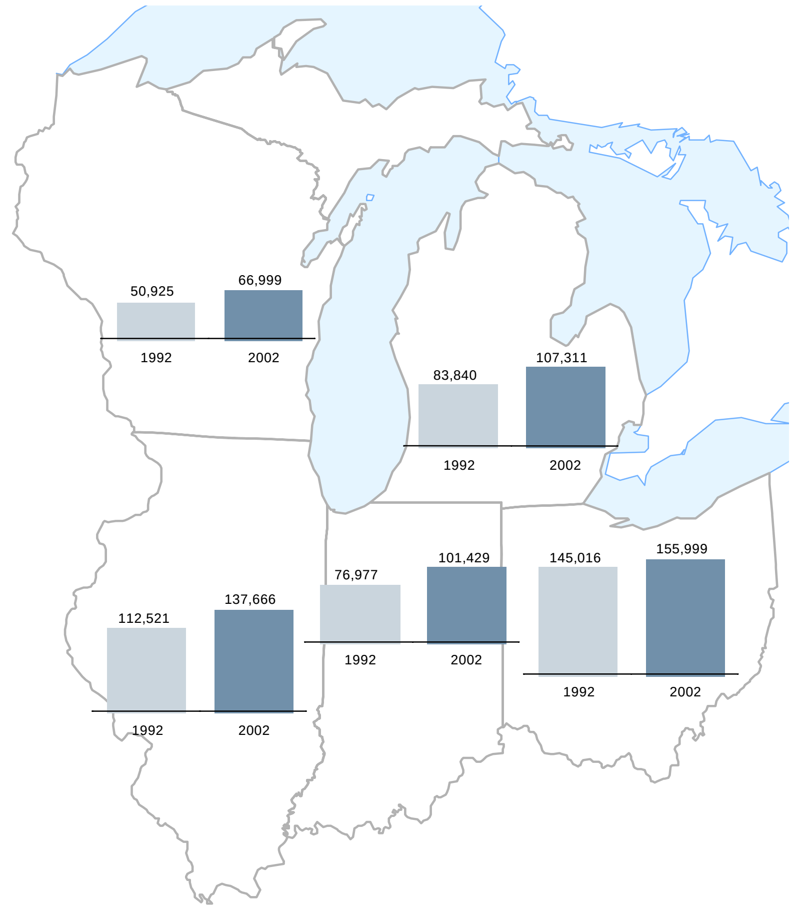
Source: Energy Information Administration, U.S. Department of Energy.

In 2002, the Midwest consumed 569,000 gigawatt hours (gWh) of electric power. Electric power consumption in 2002 was 20 percent higher than 1992 consumption, representing an annual increase of about 2 percent per year.

Retail sales of power were highest in Ohio and Illinois in 2002. Indiana and Wisconsin both saw increases in retail sales of electric power of more than 30 percent from 1992 to 2002.

Figure A11-2 shows the retail sales of electric power by state for 1992 and 2002.

Figure A11-2.
Retail sales of electric power in gigawatt hours (gWh), 1992-2002

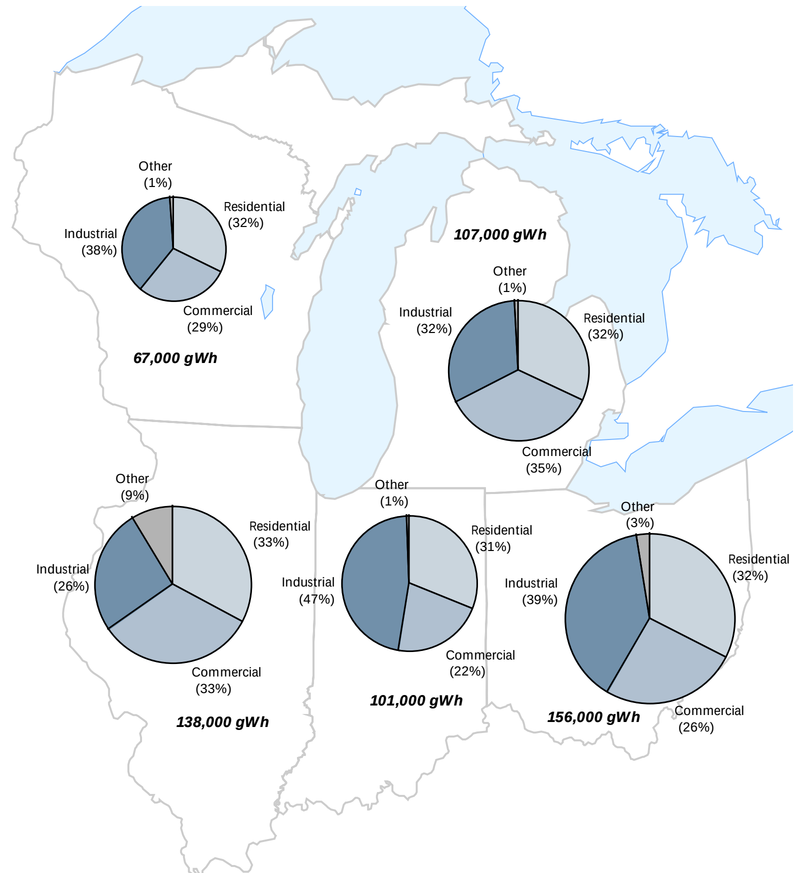


Note: Data in gigawatt hours (gWh).
Source: Energy Information Administration, U.S. Department of Energy.

Electric Power Industry — Retail Sales of Electricity

As shown by Figure A11-3, residential homes purchase about one-third of all the electric power sold in the Midwest. The proportion of electric power sales to the industrial sector varies by state from 26 percent (Illinois) to over 45 percent (Indiana).

Figure A11-3.
Retail sales of electric power by sector, 2002



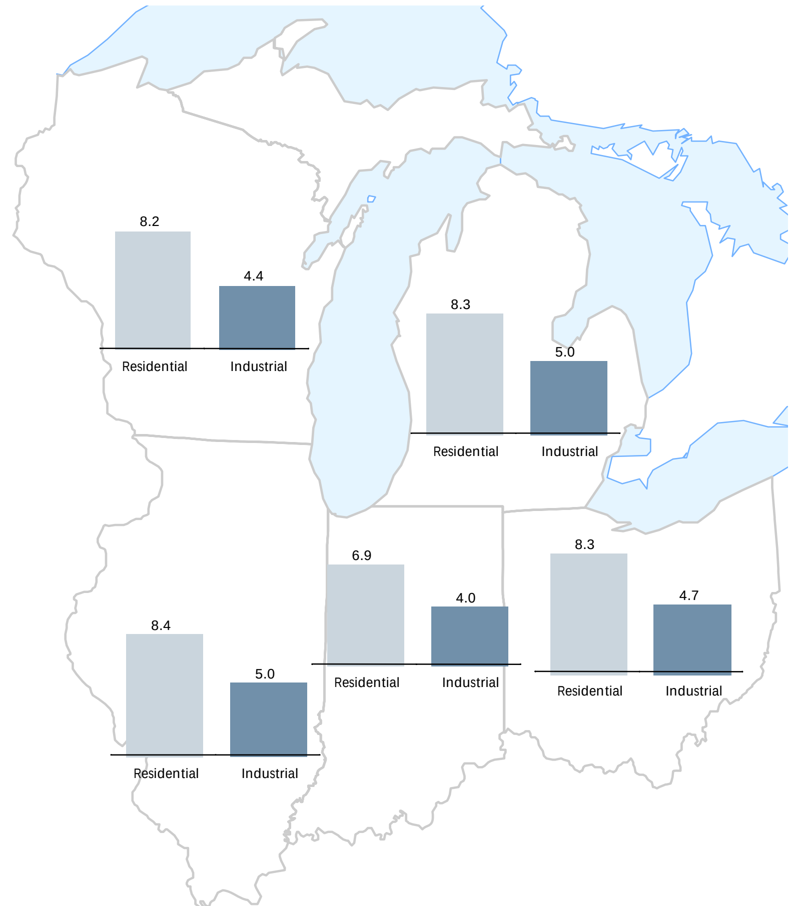
Note: Total state purchases of electric power in gigawatt hours (gWh).
Source: Energy Information Agency, U.S. Department of Energy.

The average price for power in the Midwest was 6.5 cents per kilowatt-hour in 2002. Consumers (across all sectors) in Illinois pay the most for electric power, just under 7 cents per kWh, while Indiana customers pay the least, just over 5 cents per kWh.

The average price for electric power in the Midwest for residential homes was 8.0 cents per kWh in 2002, while industrial customers paid about 4.5 cents per kWh.

Figure A11-4 shows the average price paid by both residential and industrial consumers of electric power for each state in the Midwest.

Figure A11-4.
Average price (cents per kWh) for residential and industrial sales of electric power, 2002



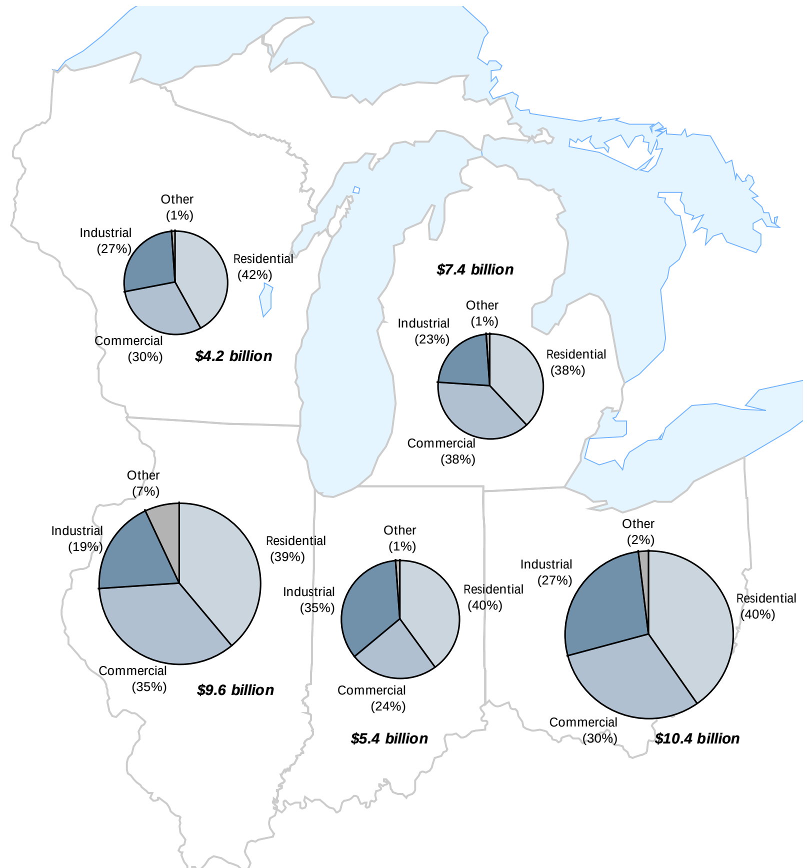
Note: Prices in cents per kWh, 2002$.
Source: Energy Information Agency, U.S. Department of Energy.

Electric Power Industry — Retail Sales of Electricity

Between 1992 and 2002, revenue generated from the sale of electric power in the Midwest increased by about 15 percent. Approximately $37.0 billion of electric power was sold in the Midwest in 2002.

As can be seen in Figure A11-5, revenue from electric power was smallest in Wisconsin; utilities in that state sold about $4.2 billion of electric power to local customers in 2002. Ohio electric power utilities had the most sales within their state in 2002 — nearly $10.5 billion.

Figure A11-5.
Revenue from retail sales of electric power by sector, 2002



Note: Revenue from sales in 2002$.

Source: Energy Information Agency, U.S. Department of Energy.

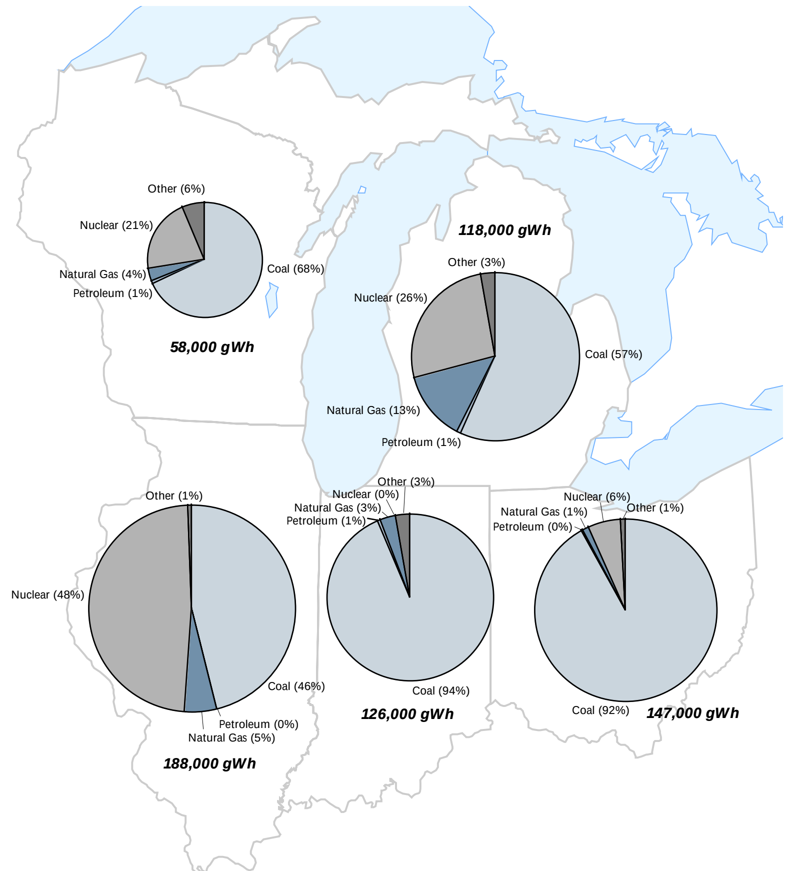
Electric Power Industry — Net Generation of Electricity

In 2002, the Midwest region generated about 16 percent of all the electric power produced in the United States, a total net generation of 637,000 gigawatt hours of electric power. Coal is the major source of electric power in the Midwest; 70 percent of all the power produced in the Midwest is done so by coal-burning power plants. Nuclear power plants produce 23 percent of the power in the Midwest, while generating units that utilize natural gas or other petroleum products account for 6 percent of all the electric power in the Midwest. Plants utilizing renewable resources generate 2 percent of the electric power in the Midwest.

Of the five states in the region, Illinois produced the most electric power in 2002 (188,000 gigawatt hours). Illinois is also the only state in which coal was not the primary source of electric power. Wisconsin produced the least amount of electricity in 2002, 58,000 gigawatt hours.

Figure A11-6 shows the total net generation of electric power by source type for each state in the Midwest in 2002.

Figure A11-6.
Net generation of electric power by source type, 2002



Note: Data in gigawatt hours (gWh).

Source: Energy Information Agency, U.S. Department of Energy.

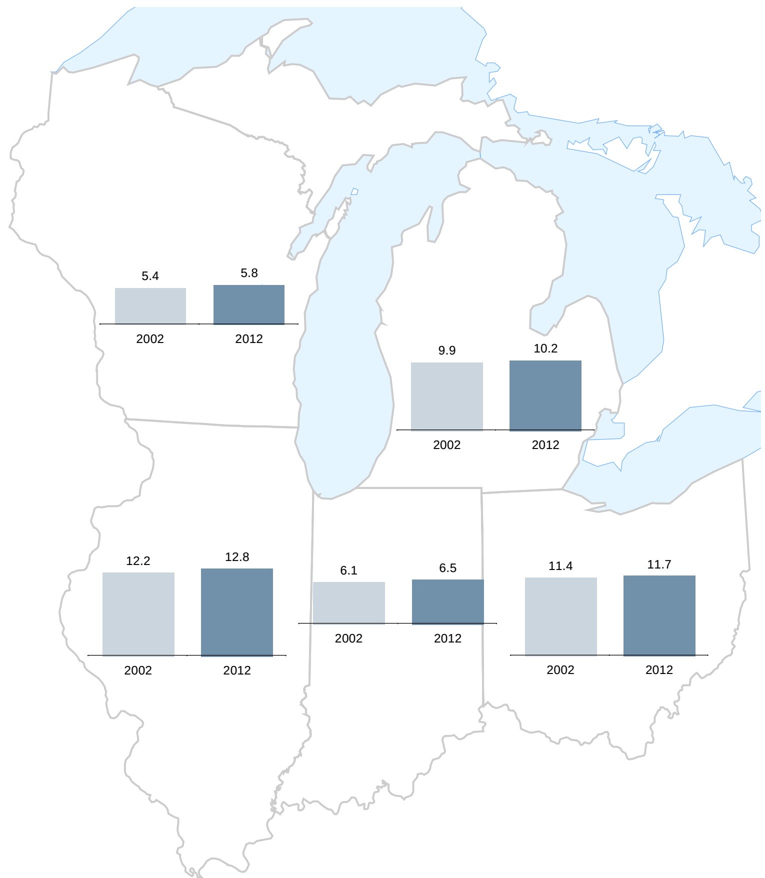
Electric Power Industry — Projected State Population

In 2002, the Midwest had a population of approximately 45.1 million people, or nearly 16 percent of the population of the United States. By 2012, the population of the Midwest is projected to grow by 4.3 percent to a total of 47.0 million.

Wisconsin is expected to grow the fastest over this period, its population increasing by 7 percent to 5.8 million residents. Ohio is expected to see the smallest population growth of the five-state region — its population is expected to increase by less than 3 percent to reach 11.7 million in 2012.

Population growth in the Midwest is expected to be modest in the near future, especially when compared to the U.S. population as a whole. In 2002, the Midwest represented nearly 16 percent of the U.S. population. But by 2012, this proportion is expected to decrease to just 15 percent.

Figure A11-7.
State population (in millions), 2002-2012



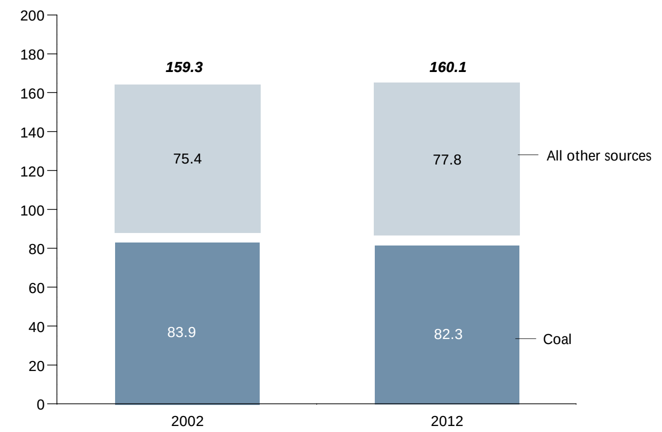
Source: State of Illinois, Office of Policy, Development, Planning and Research; Indiana Business Research Center; Michigan Office of State Demographer; Ohio Department of Development; and Wisconsin Demographic Services Center, Department of Administration.

Electric Power Industry — Projected Nameplate Capacity

The U.S. Department of Energy projects total nameplate capacity of electric power production in the Midwest to increase slightly from 2002 to 2012 (under baseline conditions). In 2012, coal-generating power plants are expected to represent just over half of all the electric power generation capacity.

Figure A11-8 shows the nameplate capacity for coal burning electric power plants as well as the nameplate capacity for electric power plants regardless of source type.

Figure A11-8.
Projected electric power nameplate capacity in the Midwest, 2002-2012



Note: All data in nameplate capacity; megawatts (MW).
Source: BBC Research & Consulting from Energy Information Agency, U.S. Department of Energy.

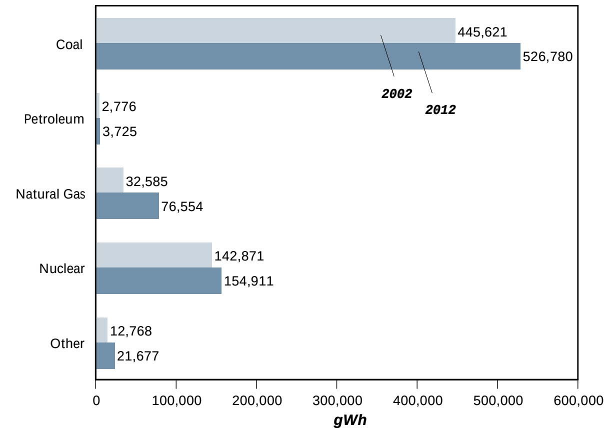
Electric Power Industry — Projected Net Generation

Net generation of electric power — the generation of electricity net the use of electricity by the power plants themselves — is anticipated to increase by nearly 25 percent between 2002 and 2012 in the Midwest.

The generation of electric power from coal-burning power plants is expected to expand by approximately 20 percent in order to meet increased demands. Generation from natural gas plants is expected to more than double between 2002 and 2012.

Figure A11-9 displays the projected net generation of electric power in the Midwest from 2002 to 2012.

Figure A11-9.
Net generation of electric power in the Midwest, 2002-2012



Note: Data in gigawatt hours (gWh).

Source: BBC Research & Consulting from Energy Information Agency, U.S. Department of Energy.

Electric Power Industry — Sales and Generation

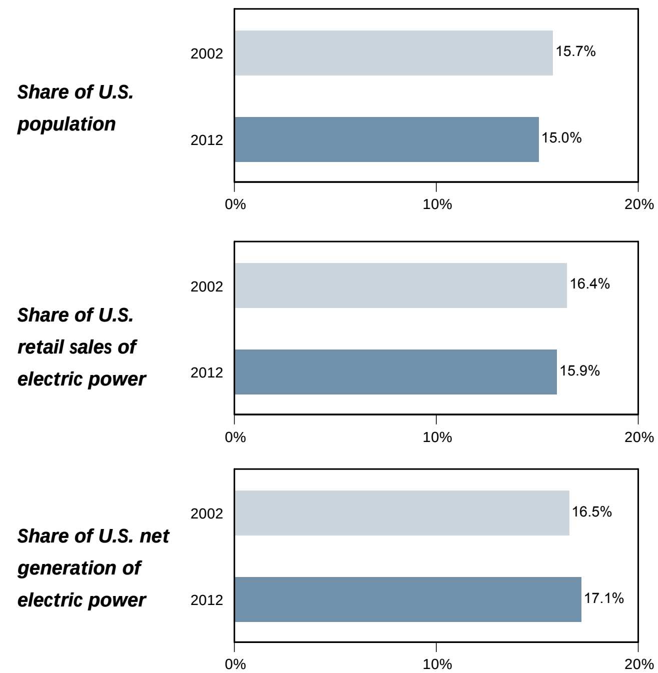
Figure A11-10 displays the Midwest's share of U.S. population, it's share of U.S. retail sales of electric power (across all sectors), and it's share of net generation of electric power.

In 2002 the Midwest represented 15.7 percent of the U.S. population. The population of the Midwest is expected to grow by a smaller rate than the rest of the country; by 2012, the Midwest population is expected to be 15.0 percent of the total U.S. population.

Corresponding to the decrease in population relative to the United States, retail sales of electricity in the Midwest are also expected to decrease relative to all electric power sold in the United States.

Electric power production in the Midwest is expected to increase slightly relative to all U.S. production. In 2002, the Midwest produced 16.5 percent of all the electric power in the United States. By 2012, this proportion is expected to be just more than 17 percent.

Figure A11-10.
Midwest share of U.S. population, retail sales of electric power, and net generation of electric power, 2002-2012



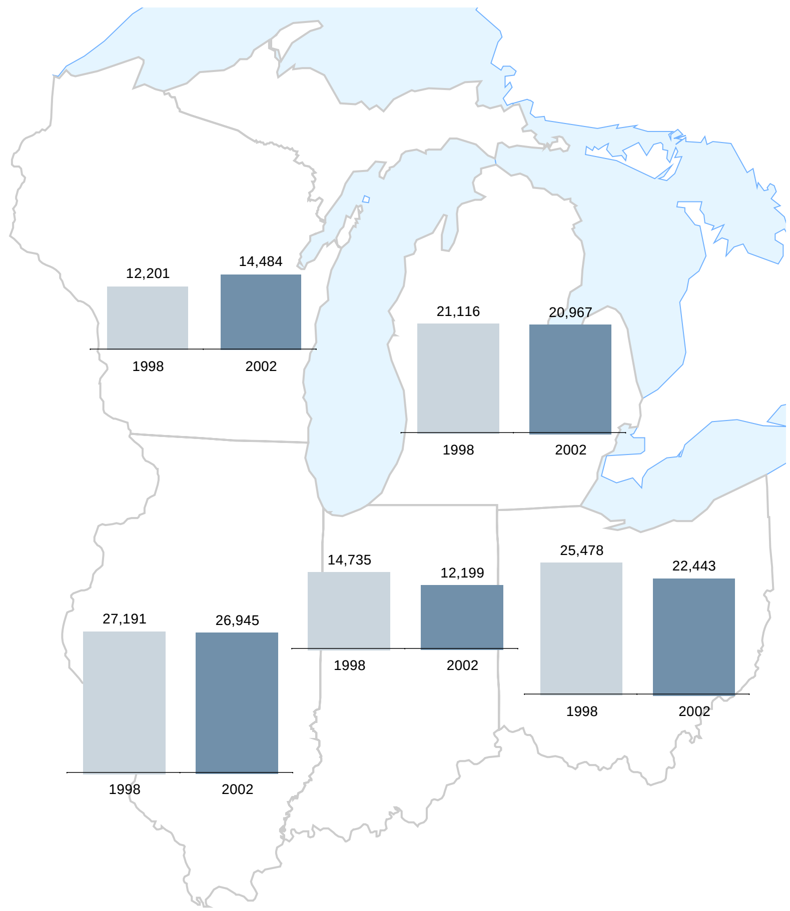
Source: State population projections (see Figure EPI-7) and U.S. Census Bureau.
BBC Research & Consulting from Energy Information Agency, U.S. Department of Energy.

Electric Power Industry — Employment Trends

Between 1998 and 2002, employment in the electric power industry in the Midwest region decreased by nearly 10 percent. The electric power industry in Ohio saw the largest decrease in employment over this period, a decrease in employment by 30 percent. Wisconsin, however, saw a slight increase in employment in this industry between 1998 and 2002.

Figure A11-11 shows historical levels of employment in the electric power industry.

Figure A11-11.
Employment in the electric power industry, 1998 and 2002



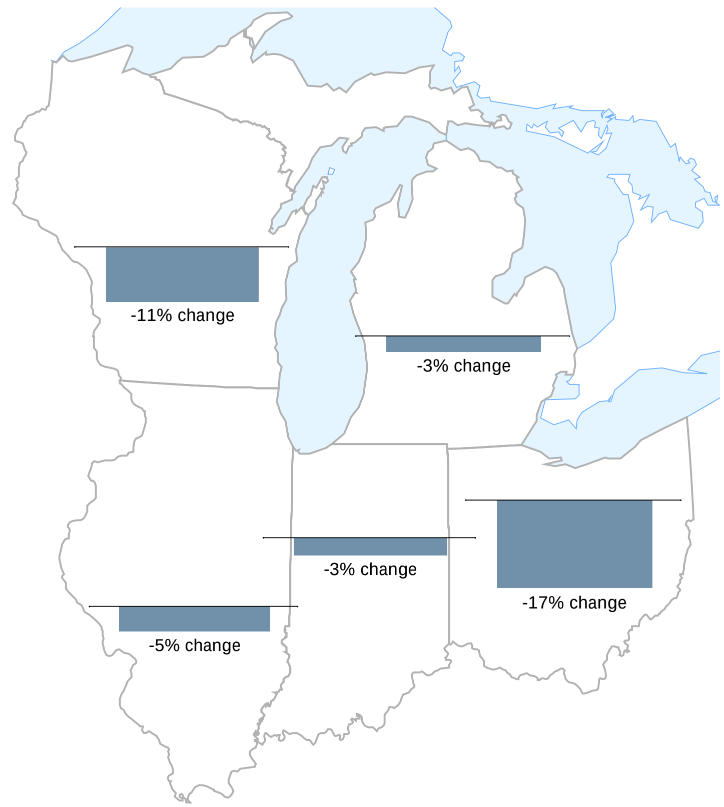
Source: U.S. Census Bureau, County Business Patterns.

Electric Power Industry — Employment Forecasts

Employment within the electric power industry is expected to continue to decrease. Between 2002 and 2012 Midwest employment in this sector is expected to decline by 8 percent. Each state in the region expects to see a decrease in employment within this industry between 2002 and 2012.

Figure A11-12 displays the projected change in employment in the sector between 2002 and 2012.

Figure A11-12.
Projected change in employment
in the electric power industry, from 2002 to 2012



Source: Illinois Department of Employment Security; Indiana Department of Workforce Development; Ohio Department of Job and Family Services; Michigan Department of Labor and Economic Growth; Wisconsin Department of Workforce Development.

APPENDIX B.
Industry Impacts by State

Industry Impacts by State

In the main body of the report (Sections IV-VI), BBC provided estimates of the economic impacts of the LADCO scenarios on each case study industry, and impacts from reductions in disposable income available to households. In those sections, we also provided estimates of the total economic impacts on a state by state basis.

Reviewers of earlier drafts of this information requested further details, including a state by state breakdown of impacts on each case study industry. This appendix provides those estimates.

We believe this information should be interpreted with some caution. The approach used in this study is most reliable in estimating effects by industry across all five states and in estimating total effects at the state level. Accurately projecting the geographic distribution of output and employment impacts within the region on a particular case study industry would require an examination of financial conditions and competitiveness at the individual firm level, which was well beyond the scope of this study. Nonetheless, the data in this section may provide insight into which sectors in a particular state are most at risk from increased electric rates.

Exhibit B-1.
Projected job reductions in Illinois by industry

	2012		2013		
			EGU1/EGU2 Without Replacement Power	With Replacement Power	
Case Study Industries	***IM1***	***IM2***		***EGU1***	***EGU2***
Direct Impacts					
Food products	3 – 33	20 – 151	33 – 255	32 – 239	49 – 380
Paper	4 – 4	5 – 23	22 – 37	19 – 35	34 – 58
Chemicals	13 – 44	59 – 198	101 – 332	95 – 310	149 – 492
Plastics & rubber manufacturing	13 – 45	64 – 204	109 – 348	103 – 321	162 – 515
Primary metals	4 – 11	19 – 57	30 – 94	30 – 91	45 – 138
Fabricated metals	6 – 42	32 – 202	49 – 336	49 – 318	79 – 502
Machinery manufacturing	9 – 25	37 – 113	61 – 192	55 – 176	93 – 284
Computer manufacturing	6 – 13	28 – 61	41 – 98	45 – 94	71 – 151
Transportation equipment	3 – 8	16 – 32	26 – 52	23 – 49	37 – 79
Coal mining	0 – 0	0 – 0	436 – 436	436 – 436	509 – 509
Secondary Impacts	***62 – 237***	***298 – 1,156***	***1,409 – 2,840***	***1,381 – 2,701***	***2,309 – 4,430***
Household Spending Impacts	***890 – 890***	***4,060 – 4,060***	***6,940 – 6,940***	***6,500 – 6,500***	***10,270 – 10,270***
Total Impacts	1,013 – 1,352	4,638 – 6,257	9,257 – 11,960	8,768 – 11,270	13,807 – 17,808

Note: Totals may not precisely match information provided in other sections of this report.

Source: BBC Research & Consulting, 2005.

As shown in Exhibit A2-1, the Illinois industries most at risk due to higher electricity costs under the potential LADCO scenarios include plastics and rubber manufacturing, chemicals and fabricated metals — along with coal mining.

Exhibit B-2.
Projected job reductions in Indiana by industry

Case Study Industries	2012 IM1	2012 IM2	2013 EGU1/EGU2 Without Replacement Power	2013 With Replacement Power EGU1	2013 With Replacement Power EGU2
Direct Impacts					
Food products	15 – 100	24 – 143	35 – 239	34 – 234	48 – 311
Paper	8 – 16	5 – 24	22 – 38	23 – 36	27 – 48
Chemicals	64 – 206	88 – 287	145 – 471	144 – 469	188 – 613
Plastics & rubber manufacturing	93 – 279	127 – 398	214 – 655	213 – 654	279 – 859
Primary metals	62 – 193	88 – 268	146 – 439	143 – 437	189 – 568
Fabricated metals	28 – 170	37 – 241	65 – 399	64 – 393	84 – 518
Machinery manufacturing	29 – 94	44 – 138	74 – 225	72 – 224	99 – 296
Computer manufacturing	23 – 54	35 – 70	77 – 110	55 – 112	68 – 147
Transportation equipment	75 – 157	106 – 224	170 – 359	168 – 355	224 – 472
Coal mining	0 – 0	0 – 0	1,619 – 1,619	1,619 – 1,619	1,884 – 1,884
Secondary Impacts	***880 – 2,829***	***1,290 – 4,247***	***5,553 – 10,323***	***5,474 – 10,220***	***8,437 – 14,564***
Household Spending Impacts	***4,120 – 4,120***	***5,780 – 5,780***	***9,600 – 9,600***	***9,540 – 9,540***	***12,480 – 12,480***
Total Impacts	5,397 – 8,218	7,624 – 11,820	17,720 – 24,477	17,549 – 24,293	24,007 – 32,760

Note: Totals may not precisely match information provided in other sections of this report.

Source: BBC Research & Consulting, 2005.

After coal mining, plastics & rubber manufacturing in Indiana is projected to experience the largest job losses of any of the case study industries under all of the potential LADCO scenarios. Chemical manufacturing, primary metals and fabricated metal manufacturing are also projected to potentially decline by 500 jobs or more under the EGU2 scenario, as shown in Exhibit B-2.

Exhibit B-3.
Projected job reductions in Michigan by industry

Case Study Industries	2012 IM1		2012 IM2		2013 EGU1/EGU2 Without Replacement Power		2013 With Replacement Power EGU1		2013 With Replacement Power EGU2	
Direct Impacts										
Food products	9 –	44	10 –	75	14 –	91	14 –	86	23 –	136
Paper	6 –	10	4 –	16	9 –	18	9 –	15	15 –	28
Chemicals	25 –	76	38 –	127	47 –	152	44 –	143	71 –	229
Plastics & rubber manufacturing	37 –	112	65 –	193	80 –	236	73 –	221	118 –	359
Primary metals	12 –	39	23 –	65	27 –	77	23 –	73	39 –	118
Fabricated metals	14 –	102	29 –	168	34 –	201	34 –	188	48 –	305
Machinery manufacturing	22 –	66	40 –	113	47 –	138	46 –	130	72 –	212
Computer manufacturing	9 –	18	15 –	33	13 –	39	16 –	33	29 –	56
Transportation equipment	64 –	133	106 –	222	127 –	265	119 –	247	192 –	398
Coal mining	0 –	0	0 –	0	0 –	0	0 –	0	0 –	0
Secondary Impacts	***448 –***	***1,293***	***770 –***	***2,317***	***936 –***	***2,795***	***888 –***	***2,604***	***1,467 –***	***4,308***
Household Spending Impacts	***2,630 –***	***2,630***	***4,350 –***	***4,350***	***5,330 –***	***5,330***	***5,010 –***	***5,010***	***7,990 –***	***7,990***
Total Impacts	3,276 –	4,523	5,450 –	7,679	6,664 –	9,342	6,276 –	8,750	10,064 –	14,139

Note: Totals may not precisely match information provided in other sections of this report.

Source: BBC Research & Consulting, 2005.

In Michigan, the transportation equipment manufacturing sector is projected to experience the largest impacts among the case study industries, followed by fabricated metals and plastics & rubber manufacturing. These results are shown in Exhibit B-3.

Exhibit B-4.
Projected job reductions in Ohio by industry

Case Study Industries	2012 IM1	2012 IM2	2013 EGU1/EGU2 Without Replacement Power	2013 With Replacement Power EGU1	2013 With Replacement Power EGU2
Direct Impacts					
Food products	18 – 105	18 – 120	32 – 214	32 – 209	37 – 242
Paper	14 – 24	5 – 24	25 – 42	23 – 44	29 – 50
Chemicals	48 – 160	53 – 172	94 – 311	94 – 303	107 – 350
Plastics & rubber manufacturing	93 – 286	99 – 313	185 – 563	178 – 555	207 – 645
Primary metals	37 – 113	42 – 125	71 – 222	71 – 219	83 – 250
Fabricated metals	33 – 198	35 – 220	60 – 395	60 – 388	72 – 447
Machinery manufacturing	33 – 109	37 – 119	71 – 213	69 – 212	79 – 240
Computer manufacturing	20 – 39	18 – 39	28 – 73	35 – 69	40 – 80
Transportation equipment	51 – 107	56 – 116	98 – 205	95 – 200	111 – 234
Coal mining	0 – 0	0 – 0	1,828 – 1,828	1,828 – 1,828	1,967 – 1,967
Secondary Impacts	***664 – 2,157***	***732 – 2,500***	***5,108 – 8,270***	***5,086 – 8,151***	***7,486 – 10,990***
Household Spending Impacts	***4,490 – 4,490***	***4,870 – 4,870***	***8,820 – 8,820***	***8,630 – 8,630***	***9,960 – 9,960***
Total Impacts	5,501 – 7,788	5,965 – 8,618	16,420 – 21,156	16,201 – 20,808	20,178 – 25,455

Note: Totals may not precisely match information provided in other sections of this report.

Source: BBC Research & Consulting, 2005.

As in Indiana, the largest impacts of the potential LADCO control strategies in Ohio would fall on the local coal mining industry with nearly 2,000 jobs estimated to be at risk under EGU2. After coal mining, plastics and rubber manufacturing and fabricated metals are anticipated to have the most jobs at risk — as shown in Exhibit B-4.

Exhibit B-5.
Projected job reductions in Wisconsin by industry

			2013		
	2012		EGU1/EGU2 Without Replacement Power	With Replacement Power	
Case Study Industries	IM1	IM2		EGU1	EGU2
Direct Impacts					
Food products	11 – 83	15 – 125	23 – 158	19 – 139	38 – 287
Paper	14 – 26	9 – 36	26 – 45	24 – 41	48 – 83
Chemicals	12 – 38	18 – 55	21 – 70	18 – 61	39 – 125
Plastics & rubber manufacturing	26 – 90	45 – 132	52 – 172	46 – 146	98 – 306
Primary metals	12 – 31	12 – 43	18 – 55	18 – 49	31 – 97
Fabricated metals	13 – 83	20 – 123	26 – 155	19 – 136	44 – 285
Machinery manufacturing	20 – 57	27 – 84	37 – 112	31 – 96	64 – 201
Computer manufacturing	12 – 18	16 – 29	13 – 38	16 – 33	31 – 67
Transportation equipment	8 – 17	11 – 25	14 – 30	14 – 27	28 – 55
Coal mining	0 – 0	0 – 0	0 – 0	0 – 0	0 – 0
Secondary Impacts	***134 – 539***	***199 – 844***	***260 – 1,076***	***229 – 936***	***480 – 1,980***
Household Spending Impacts	***1,270 – 1,270***	***1,880 – 1,880***	***2,360 – 2,360***	***2,110 – 2,110***	***4,350 – 4,350***
Total Impacts	1,532 – 2,252	2,252 – 3,376	2,850 – 4,271	2,544 – 3,774	5,251 – 7,836

Note: Totals may not precisely match information provided in other sections of this report.

Source: BBC Research & Consulting, 2005.

Without any active coal mines, the case study industries that could experience the largest job losses under the potential LADCO scenarios in Wisconsin include plastics and rubber manufacturing, food products, fabricated metals and machinery manufacturing. These results are shown in Exhibit B-5.

EVALUATION OF THE MIDWEST RPO INTERIM MEASURES AND EGU1 AND EGU2

Submitted On Behalf of
Midwest Ozone Group

Submitted to
Midwest Regional Planning Organization

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August 1, 2005

I. INTRODUCTION

In January 2005, the Midwest Regional Planning Organization (MRPO) issued a White Paper that outlined a possible set of control measures that electric generating units within the states of Illinois, Indiana, Michigan, Ohio and Wisconsin would have to meet beginning in 2008 and with final implementation being 2013. These control measures would establish regional emission caps based upon specified emission rates for both NOx and SO2. There are two sets of emission rates that are described in the White Paper, which can be referred to as Intermediate Measures (IM) 1 and 2 and Electric Generating Unit (EGU) 1 and 2.

In IM1, a regional cap is proposed based upon emission rates of 0.36 and 0.15 lbs/mmbtu, respectively, for SO2 and NOx. The second intermediate measure, referred to as IM2, proposes a regional cap based upon emission standards of 0.24 and 0.12 lbs/mmBtu, respectively, for SO2 and NOx. These IM regional caps would apply from 2008 to 2012.

In terms of EGU1, a regional cap is proposed based upon emission rates 0.15 and 0.10 lbs/mmbtu, respectively, for SO2 and NOx. The final EGU scenario, identified as EGU2, proposes a regional cap based upon emission rates of 0.10 and 0.07 lbs/mmbtu, respectively, for SO2 and NOx. Implementation of these EGU caps would begin in 2009 with full implementation in 2013. As you can see there is an overlap between IM and EGU scenarios. For the purposes of this analysis, we evaluated compliance for the IM1 and IM2 in 2012 and compliance for EGU1 and EGU2 in 2013.

Of particular note, during this 2012 – 2013 time period the On-the-Books emission rates that would be in effect within the 5-State Region attributed to the Clean Air Interstate Rule (CAIR) are 0.58 and 0.15 lbs/mmbtu, respectively, for SO2 and NOx.

The purpose of this analysis is to provide the reader with a comparative evaluation of the compliance implications of meeting the reduction targets proposed by IM1 & IM2 and EGU1 & EGU2 by fossil electric generating units in the 5-State Region. This analysis not only evaluates the level of capital investment and annual compliance costs attributed to each scenario, but also illustrates the marginal cost of control for SO2 and NOx, the level of potential capacity at-risk in achieving the reduction targets of each scenario and the level of local coal that could be displaced due to compliance.

In terms of modeling, each scenario was modeled independent of each other; therefore, there were no compliance phases. In addition, due to the stringency of EGU1 and EGU2, the modeling was in two phases: (i) initial compliance to meet the EGU caps without regard to costs; and, (ii) evaluation of the expected costs to meet EGU caps.

II. METHODOLOGY

To undertake this study, we employed the *Emission-Economic Modeling System (EEMS)*, a computer model designed to undertake emission and economic analyses of environmental polices and regulations. The modeling system contains a rich database describing the electric generating sector, covering unit design and operating characteristics, environmental control equipment and emission rates.

In general, *EEMS* identifies a combination of control options (technology versus allowances) that approximates the least cost solution for a given utility system or regulatory (trading) regime. The order in which individual units are assumed to deploy their initial compliance option is determined by their dispatch order and generation costs with the cheapest units are assumed to deploy control technology first. The total tons reduced are then compared to the reduction target. If calculated emissions are above the target, *EEMS* then systematically assigns more stringent control technology, in order of increasing generation costs, until the reduction target is achieved. Likewise, if the calculated emissions are significantly below the emission target, *EEMS* will begin to remove the most expensive control technology until the emissions a very close to the cap, taking into account any required control margin to account for unexpected events.

Regional NOx and SO2 Budgets: As mentioned earlier, the stipulated emission rates for both IM1 & IM2 and EGU1 & EGU2 would be used to establish regional emission caps or budgets for affected electric generating units within the 5-State Region. The computed budgets for NOx and SO2 for each scenario that were modeled are presented in Table 1.

TABLE 1
REGIONAL NOx AND SO2 BUDGETS
(tons)

Scenario	NOx	SO2
CAIR	399,895	1,046,659
IM 1	376,037	860,956
IM 2	300,830	573,971
EGU 1	250,069	358,732
EGU 2	175,484	239,154

The regional NOx budget for both IM and EGU scenarios was determined by following Clean Air Interstate Rule (CAIR) allocation process, as outlined in the final rule. The SO2 regional budget for both IM and EGU scenarios was based upon an alternative to the CAIR allocation process, which is based upon Title IV – Phase II allocations. The alternative allocation process used the average heat input for the years 2000 – 2004 from EPA's Continuous Emission Monitoring (CEM) data for Acid Rain units. Appendix A presents a description of the method and data used to compute both NOx and SO2 budgets.

Affected units, which are defined as units that would have to meet the reduction targets of IM or EGU scenarios, are fossil units >25 MW that sell electricity to the grid. Under the proposed regulatory regime evaluated in this analysis, electric generators would be able to bank and trade SO2 and NOx allowances within the 5-State Region, but no Title IV SO2 allowances could be carried over for compliance.

Generation and Fuel Assumptions: In this analysis, *EEMS* developed a generation forecast for electric power sector fossil generating units within the following North America Electric Reliability Council (NERC) regions: East Central Area Reliability Coordination Agreement (ECAR); Mid-America Interconnected Network (MAIN) and Mid-Continent Area Power Pool (MAPP). The basis of this forecast was the projected regional electric demand by fuel type from Energy Information Administration's (EIA) *Annual Energy Outlook 2005 (AEO2005)*. In addition, future regional coal and gas prices were also based upon EIA's *AEO2005*.

Compliance and Control Technology Choices: Those control options that were evaluated in this analysis to meet the reduction targets of either IM1 & IM2 or EGU1 & EGU2 are as follows:

- SO2 Controls
    - Base Wet Flue Gas De-Sulfurization (FGD) System with SO2 removal efficiencies of 90 and 95 percent for Powder River Basin (PRB)/sub-bituminous and bituminous coals, respectively;
    - High Performance Wet FGD System with SO2 removal efficiencies of 94 and 98 percent for PRB/sub-bituminous and bituminous coals, respectively;
    - FGD Upgrade for existing FGD systems with removal efficiencies at or below 90 percent to 93 percent;
    - Fuel Switching from a high sulfur coal to a low sulfur PRB coal; and,
    - Fuel Switching Existing and Retrofitted FGD (FGD-FS) systems a fuel switch from a high sulfur bituminous coal to a low sulfur coal from the Powder River Basin of Wyoming .

- NOx Controls
    - Combustion Modifications install controls on units that exceed specified NOx emission rates;[1]
    - Selective Non-Catalytic Reduction (SNCR) with NOx removal efficiencies upwards to 45 percent depending on size; and,
    - Selective Catalytic Reduction (SCR) limited to 90 percent removal or specified floors depending on coal type.

The selection of specific compliance technologies by the model is not intended to replicate an individual company's compliance decisions; however, the model results are based upon the application of a set of control assumptions that are uniformly applied across the entire boiler population within a specific (geographical) jurisdiction based upon unit specific information contained in the model's data base.

Capital and operating costs were developed based upon information in the public domain about recent control technology installations. It should be noted, that the above mentioned

[1] Combustion Modifications were modeled to be used in combination with either SNCR or SCR.

control assumptions represent realistic assumptions, in terms of applicability and performance. Further details of these control assumptions and costs are described in Appendix B.

III. REGIONAL EMISSIONS AND CONTROL CAPACITY

Electric generating units within the 5-State Region are currently complying with regulatory requirements of Title IV, NOx SIP Call, specific NSR consent decrees, as well as specific BACT requirements for new sources. Beginning in 2009, electric generating units within the 5-State Region will have to meet the targets and timetables specified in CAIR. To meet these regulatory initiatives, electric generators within the five states have or will be installing SO2 and NOx control technologies through 2012, as shown in the table below.

TABLE 2

SUMMARY OF REGIONAL ELECTRIC GENERATING SO2 AND NOX CONTROLLED CAPACITY: 2012

Element	Capacity (GW)	% of Regional Capacity
Coal-fired Capacity (>25 MW)	82.7	
FGD	40.7	49.2
SCR	48.6	59.8
SNCR	16.5	19.9

In 2012, the electric generators are expected to have 82.7 GW of coal-fired capacity available within the 5-State Region. In response to CAIR and other On-the-Books regulatory mandates by 2012, 49.2 percent (or 40.7 GW) of this existing capacity is expected to have FGD systems operating. Also by the end of 2009, 43 percent of the region’s coal-fired capacity will be burning low sulfur coal from the PRB.

In terms of NOx controls, by 2012 almost 60 percent of the region’s coal-fired capacity (48.6 GW) will be equipped with SCR technology, while an additional 20 percent (16.5 GW) of the region’s coal-fired capacity will have SNCR technology. This would mean almost 80 percent of the region’s 2012 coal-fired capacity will have some kind of post-combustion NOx controls.

The installation of these SO2 and NOx controls are expected to have a significant impact on both SO2 and NOx emissions within the five states between 2003 and 2012, as illustrated in the Table 3.

TABLE 3

REGIONAL EGU SO2 AND NOx EMISSIONS: 2003, 2009 and 2012

Parameter	2003	2009	2012
Heat Input: TBtu	4,817	5,871	5,991
SO2: Tons	2,896	2,322,306	1,631,714
SO2: lbs/mmbtu	1.20	0.79	0.54
NOx: Tons	921,884	403,918	380,050
NOx: lbs/mmbtu	0.38	0.14	0.13

As shown above between 2003 and 2012 regional electric generating fossil heat input is projected to increase by 24.4 percent, while both SO2 and NOx emissions are expected to decline by 43.7 and 58.8 percent, respectively. These emission decreases illustrate the effect current and future On-the-Books regulations are expected to have upon regional emissions.

IV. COMPLIANCE EFFECTS OF MEETING IM1 AND IM2

In order to meet the IM1 and IM2 reduction targets in 2012, electric generators within the 5-State Region would have to make an initial capital investment of $9.5 billion and $15.5 billion, respectively on SO2 and NOx control technologies, as shown in Table 4.[2] Generators within these five states would incur annualized compliance costs in 2012 of $2.0 billion and $3.2 billion, respectively for IM1 and IM2 in order to achieve their respective regional SO2 and NOx caps.[3]

TABLE 4

IM1 AND IM2 COMPLIANCE COSTS AND EMISSION REDUCTIONS IN THE FIVE STATES: 2012
(2003$)

Simulation	Capital	Annualized	SO2 MC ($/ton)	NOx MC ($/ton)	SO2 Emissions	NOx Emissions
CAIR			1,052	2,584	1,631,000	380,000
IM1	9.5B	2.0B	2,598	4,122	860,000	376,000
IM2	15.5B	3.2B	5,029	4,669	573,000	300,000

Note: 1. MC represents the marginal cost of control, which is the cost of the last unit to achieve compliance.

These investments will reduce both SO2 and NOx emissions within the five states from the projected CAIR levels, as shown in Table 4. However, to achieve both IM1 and IM2 SO2

[2] Initial capital investment is defined as the capital required to SO2 and NOx control equipment that would be in service by 2012.
[3] Annualized compliance costs are defined as the annual capital charge (including taxes and insurance), annual operation and maintenance costs, changes in fuel costs generators need to pay to operate SO2 and NOx control equipment.

caps, SO2 control technology would have to be installed on units between 56 and 60 years old. As shown in Table 5, FGD capacity within the 5-State Region would reach 59.1 GW under IM1 and 75.4 GW under IM2, which translates into 71.5 percent and 91.2 percent of region's total coal-fired capacity being equipped with FGD systems, respectively. In addition, under IM1 2.2 GW of existing FGD capacity and 4.6 GW of existing FGD capacity would be upgraded to achieve a SO2 removal efficiency of 93 percent (FGD – Upgrade).

TABLE 5

FIVE STATE SO2 AND NOX CONTROL CAPACITY UNDER IM1 & IM2: 2012 (GW)

Technology	5-State (CAIR)	IM1	IM2
FGD	40.7	59.1	75.4
FGD - Upgrade	1.5	2.2	4.6
SCR	48.6	55.3	61.5
SNCR	16.5	9.0	5.8

In terms of NOx, projected SCR capacity under IM1 would reach 55.3 GW, while under IM2 SCR capacity would be operating on 75.4 GW. This SCR capacity translates into almost 67 percent and 75 percent of the region's coal-fired capacity operating SCRs under IM1 and IM2, respectively.

The major consequence of deploying SO2 control technology on these older units significantly raises the marginal costs of control, as depicted in Table 4, to meet the IM1 and IM2 caps. This technology deployment under IM1 and IM2 potentially puts at risk (units that could be retired) 4.8 GW and 8.5 GW of coal-fired capacity, respectively in the 5-State Region. Another consequence relates to the IM1 & IM2 NOx caps, which forces generators to switch from less expensive SNCR technology under CAIR to more expensive SCR technology to meet the reduction targets of both IM measures. This technological shift results in a marginal cost of compliance of $4,669/ton of NOx removed.

V. COMPLIANCE EFFECTS OF MEETING EGU1 AND EGU2

Initial Evaluation of EGU1 and EGU2

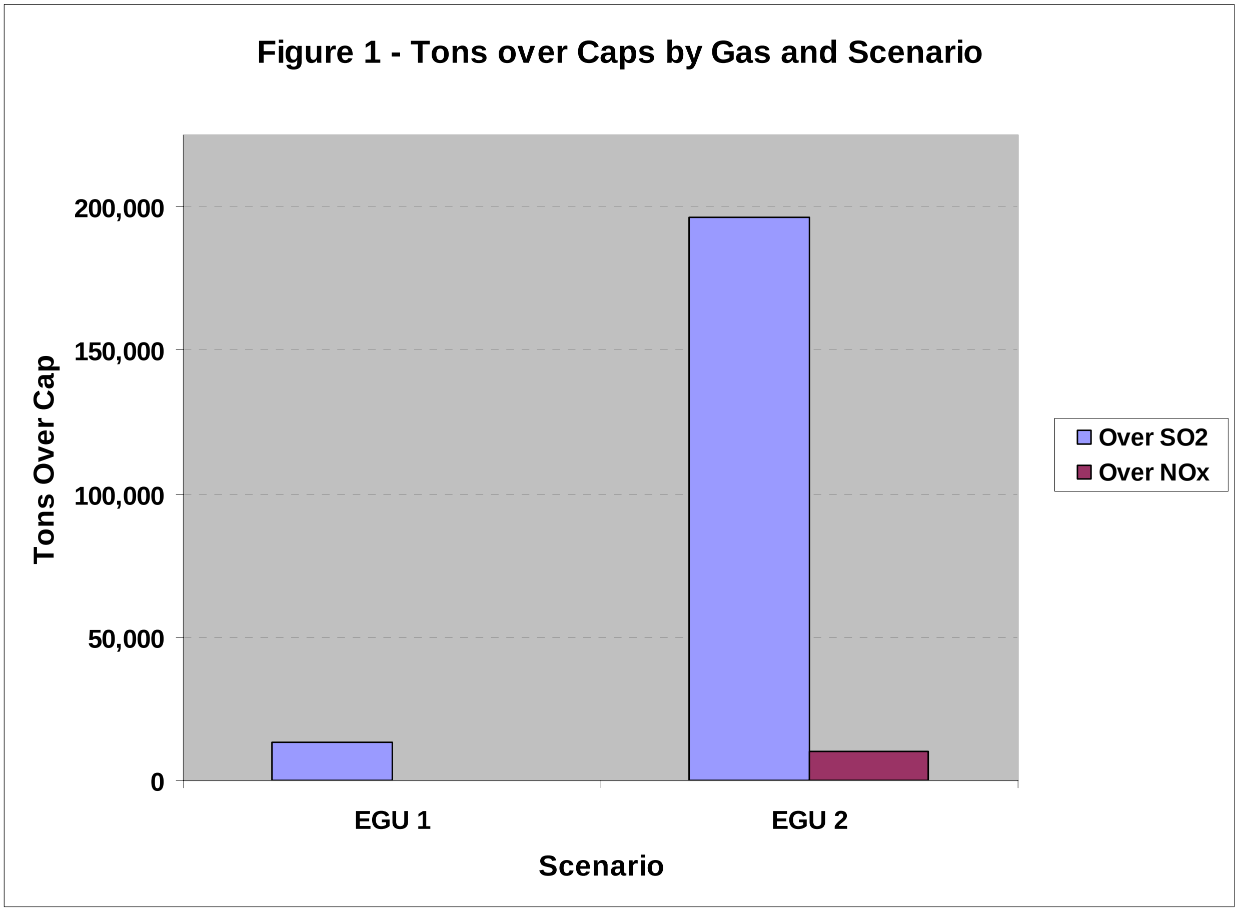
To meet the more stringent EGU1 and EGU2, electric generators in the five states would require an initial capital investment of $20.4 billion and $20.5 billion for SO2 and NOx controls, respectively for EGU1 and EGU2, as shown in Table 6. This capital investment for both EGU1 and EGU2 would translate into an annualized compliance cost of $5.2 billion in 2013, which is more than double the compliance costs for IM1 and more than one and half times greater than the compliance costs for IM2. The stringency of these two caps, and the restrictive trading regime, can be illustrated by the marginal cost of control for both SO2 and NOx, as demonstrated in Table 6.

TABLE 6

INITIAL EGU1 AND EGU2 COMPLIANCE COSTS AND EMISSION REDUCTIONS IN THE FIVE STATES: 2013
(2003$)

Simulation	Capital	Annualized	SO2 MC ($/ton)	NOx MC ($/ton)	SO2 Emissions	NOx Emissions
CAIR (2012)			1,052	2,584	1,631,000	380,000
EGU1	20.4B	5.2B	23,472	10,169	372,000	250,000
EGU2	20.5B	5.2B	23,472	12,377	372,000	249,000

However, even with this level of capital investment in control technologies and very aggressive control assumptions, the SO2 emission reductions electric generators would achieve under both EGU1 and EGU2 *would not allow* them to meet the SO2 emission caps (See Table 1) in 2013. As shown above in Table 6, electric generator SO2 emissions in 2013, in the 5-State Region for both EGU1 and EGU2 would be 372,000 tons. These 2013 SO2 emission levels would put electric generators almost 13,000 tons above the EGU1 SO2 cap and approximately 133,000 tons above the EGU2 SO2 cap. In addition to not meeting either EGU1 or EGU2 SO2 caps in 2013, electric generators in the five states would also fail to meet the EGU2 NOx cap by almost 74,000 tons. This emission shortfall can be illustrated by Figure 1.



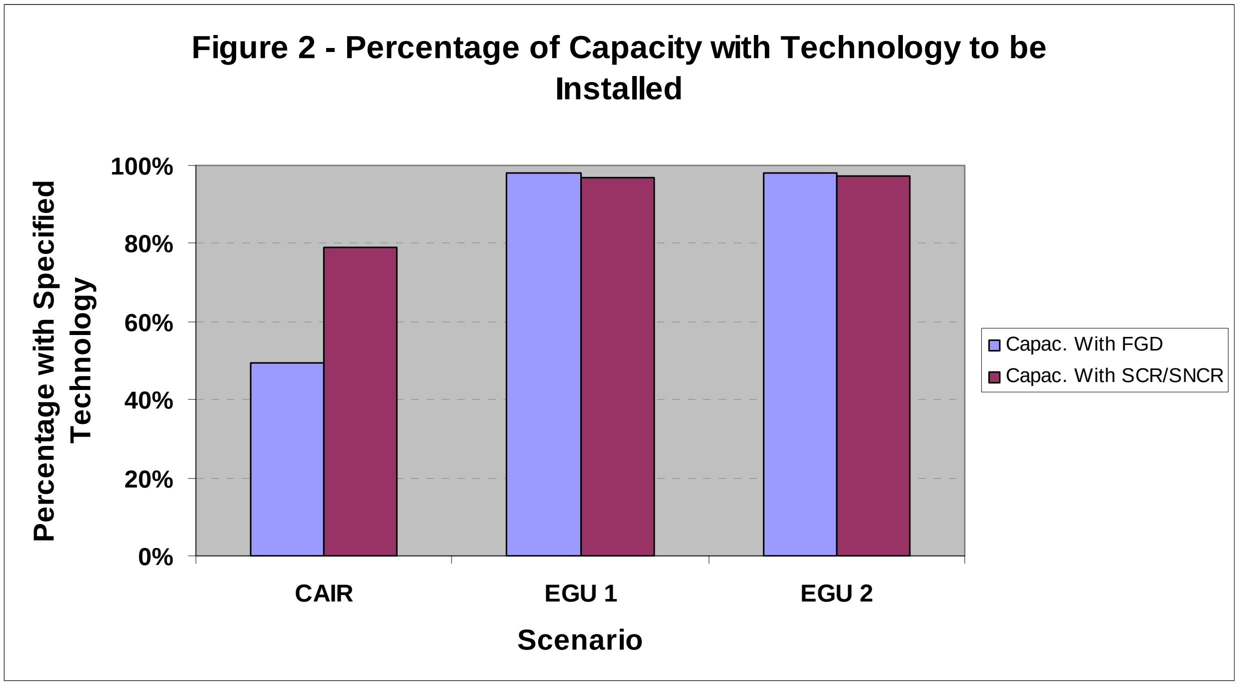
As shown in Table 7, of the 82.3 GW of coal-fired expected to be available in 2013, 80.8 GW or 98.2 percent would be equipped with FGD systems under both EGU1 and EGU2. This level of controlled FGD capacity explains why there is no change in SO2 emission levels between EGU1 and EGU2, because all units that can receive FGD systems have installed these systems by 2013.

TABLE 7

FIVE STATE SO2 AND NOX CONTROL CAPACITY UNDER EGU1 & EGU2: 2013 (GW)

Technology	5-State (CAIR)	EGU1	EGU2
FGD	40.7	80.8	80.8
FGD - FS	0	18.6	18.6
FGD - Upgrade	1.5	3.6	3.6
SCR	48.6	73.6	74.0
SNCR	16.5	6.1	6.2

This same trend follows for NOx controls, in which approximately 97 percent of the five state coal-fired capacity will have some form of post-combustion controls (SCR or SNCR) operating in 2013. The only units that do not receive SO2 and/or NOx controls are either very small (<50 MW) or very old (>60 years old) under EGU1 and EGU2.[4] Figure 2 provides an illustration of the level of SO2 and NOx controlled capacity to total capacity in 2013.



In addition to the level of FGD capacity that will be operating within the five states in 2013, 18.6 GW of this FGD capacity would have to switch from a high sulfur coal to low sulfur PRB coal in an attempt to meet the 2013 EGU1 and EGU2 SO2 caps. Also, 3.6 GW of existing FGD capacity would upgrade their SO2 removal efficiencies to 93 percent. In an attempt to meet these SO2 and NOx caps under EGU1 and EGU2, 9.9 GW of existing coal-fired capacity, with ages between 56 and 60 years old (in 2013), would be required to install FGD systems, potentially putting this capacity “at risk” of being retired.

As discussed previously, even with this level of controlled capacity and very aggressive control options, electric generators within the five states were unable to attain the 2013 SO2 caps for EGU1 and EGU1. The question then remains, why these electrical generators *can not* meet the caps of EGU1 and EGU2? The primary factors are growth in electrical demand and technological limitations. Emission caps in all cap and trade programs are based upon some kind of historical baseline (e.g., average heat input from 2000 to 2004) that requires affected sources to meet these limits in some future time period. Between the time of establishing the caps and time of compliance, electrical demand will have increase. This increase in electrical demand means greater emission reductions have to be achieved in order to meet the cap limits.

[4] Two units that did not receive SO2 and NOx controls are new Marion 1,2, & 3, which is an FBC unit, and Wabash River 1, which is an IGCC unit.

Consequently, the effective removal emission rate (emission reductions) to achieve the cap has to be below the specified emission rate that is used to establish the cap. For the EGU2 SO2 cap, which is based upon 0.10 lbs/mmbtu, the overall effective emission rate that electric generators in the five states would have to achieve to meet the cap would have to be 0.08 lbs/mmbtu. However, even employing very realistic technology assumptions the best overall effective emission rate electric generators can achieve in 2013 in the five states is 0.12 lbs/mmbtu.

Expected Costs to Meet EGU1 and EGU2

To meet the EGU1 and EGU2 caps in 2013, a specific amount of coal-fired capacity would have to be retired, since SO2 emissions exceed both cap levels and there are *no additional* controls that could be installed on the existing 2013 coal-fired capacity. As shown in Table 8, almost 0.7 GW of existing coal-fired would have to retired to meet the EGU1 SO2 cap; however, an additional 9.9 GW of older capacity (age >60 years old) could be "at risk" due to technology retrofits. In terms of EGU2, as shown in Table 8, approximately 30.2 GW of region's existing coal-fired capacity would have to be retired in order to achieve the 2013 EGU2 SO2 cap, with an additional 4.7 GW of capacity "at risk" due to age.

TABLE 8

POTENTIAL RETIREMENT CAPACITY UNDER EGU1 AND EGU2 (GW)

Scenario	Capacity Retired to Meet Caps	At Risk Capacity Due to Age	Total Potential Retirement Capacity
EGU1	0.7	9.9	10.6
EGU2	30.2	4.7	34.9

Assuming, the above-mentioned total potential retirement capacity under both EGU1 and EGU2 is retired its 2013 generation would have to be replaced. This replacement power or electrical demand would be supplied through imports from surrounding NERC regions, increased operation of existing natural gas-fired combined cycle capacity in the affected NERC regions (ECAR, MAIN and MAPP) and the construction of new gas-fired combined cycle capacity in the affected NERC regions. The 2013 net incremental replacement capacity costs for EGU1 and EGU2 would be $1.4 billion and $4.9 billion, respectively, as shown in Table 9. A brief discussion of the replacement cost methodology can be found in Appendix C.

With the retirements of the above-mentioned coal-fired capacity, their technology control costs would be removed from the region's annualized compliance costs displayed in Table 6. Therefore, the net SO2 and NOx 2013 technology control costs, which take into retirements to meet the EGU1 and EGU2 caps, would be $3.6 billion and $2.2 billion, respectively. As shown in Table 9, electric generators in the five states would be required to expend almost $5.0 billion in 2013 to meet the EGU1 cap. If electric generators would be required to meet the EGU2 cap in 2013, they would be required to spend $7.1 billion. Appendix C provides a breakdown of these costs by state.

TABLE 9

ANNUALIZED COMPLIANCE COSTS TO MEET EGU1 AND EGU2 CAPS: 2013 (2003$)

Scenario	Replacement Power	Technology	Total
EGU1	1.4B	3.6B	5.0B
EGU2	4.9B	2.2B	7.1B

Throughout this section we have discussed unit retirements and fuel switches in order to meet the EGU1 and EGU2 caps and their respective compliance costs. A direct impact of unit retirements and fuel switching existing/retrofitted FGDs from high sulfur coal to PRB coal is the effect on Illinois, Indiana and Ohio coal shipments to electric generators. Under EGU1, the projected retirements and fuel switches would displace 42.6 million tons of Illinois, Indiana and Ohio coal in 2013. In terms of EGU2, the projected retirements and fuel switches would displace almost 47.8 million tons of Illinois, Indiana and Ohio coal. A brief discussion of the assumptions and methodology used in computing the level of displaced coal can be found in Appendix C.

VI. SUMMARY OF IM1 & IM2 AND EGU1 & EGU2 COMPLIANCE COSTS

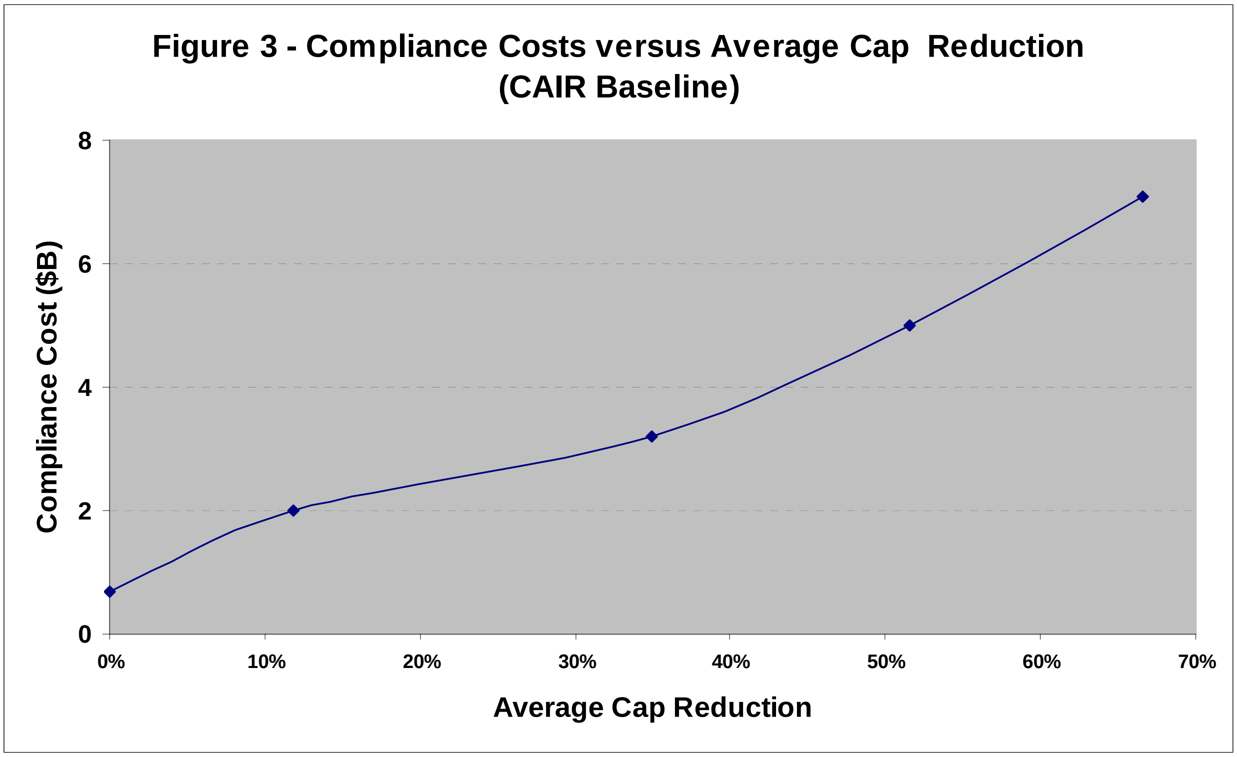
Table 10 illustrates as the regional NOx and SO2 budgets and the annualized compliance costs for each scenario.

TABLE 10

REGIONAL SO2 AND NOX BUDGETS AND ANNUALIZED COMPLIANCE COSTS

Scenario	NOx Budget	SO2 Budget	Compliance Costs
CAIR	399,895	1,046,659	0.7B
IM1	376,037	860,956	2.0B
IM2	300,830	573,971	3.2B
EGU1	250,069	358,732	5.0B
EGU2	175,484	239,154	7.1B

As demonstrated from the above table as regional NOx and SO2 budgets/caps decrease the level of compliance costs increase dramatically. For electric generators in the five states, the annualized compliance costs to meet the EGU2 NOx and SO2 emission caps is ten times greater than meeting the Phase I CAIR NOx and SO2 caps. This cost impact can be further illustrated by Figure 3 that shows the effect of increasing average cap reduction percentage from CAIR significantly increases the annualized compliance costs.



VII. CONCLUSIONS

This comparative evaluation illustrates, as regulatory scenarios become more stringent, not only do electric generating compliance costs increase significantly, but there are serious implications in meeting very extreme emission targets and timetables. However, there are major policy issues that arise in meeting the targets and timetables of IM1 & IM2 and EGU1 & EGU2, and they are:

- Compliance with the IM1 and IM2 SO2 cap could place between 4.4 GW and 8.5 GW of region's coal-fired capacity "at risk," respectively;
- The application of very aggressive control assumptions by electric generators in the five states indicate they are unable to achieve EGU1 and EGU2 SO2 emission caps and EGU2 NOx cap in 2013;
- Meeting the EGU1 and EGU2 SO2 emission caps could result in the retirement of 10.6 GW and 34.9 GW of the region's existing coal-fire capacity;
- Eventual compliance with EGU1 and EGU2, the region's electrical generators would incur annualized compliance costs that are ten times greater than they would spend on CAIR; and,
- Compliance with EGU1 and EGU2 would displace between 42.6 and 47.8 million tons of Indiana, Illinois and Ohio coal with natural gas and PRB coal.

APPENDIX A

METHODOLOGY TO DETERMINE REGIONAL NOX AND SO2 BUDGETS

The purpose of this appendix is present a brief discussion on the methods and data utilized in determining the NOx and SO2 Budgets for IM1 & IM2 and EGU1 & EGU2 within the five states that comprised the MRPO.

NOx BUDGET

As mentioned earlier, the state budgets for NOx followed the CAIR allocation process; therefore, the first step was to determine the 5-State or regional cap for NOx. This initial step involved identifying the highest annual Btu level for all Acid Units in the 5-State Region between the years 1999 to 2002. As shown in Table 1, the highest annual Btu level was selected for each state and summed to achieve a regional total.

Table 1: State Btu for Acid Rain Units: 1999 - 2002
(mmbtu)

State	Fuel	1999 HI	2000 HI	2001 HI	2002 HI	HI BTU
IL	All	895,604,720	941,011,079	933,356,252	**1,007,079,911**	**1,007,079,911**
IL	Coal	850,004,672	898,806,593	880,458,753	931,056,500	
IL	Gas	42,644,245	39,816,423	49,687,377	73,830,909	
IL	Oil	2,955,803	2,388,063	3,210,122	2,192,502	
IN	All	1,350,676,762	**1,356,985,881**	1,282,844,559	1,257,543,806	**1,356,985,881**
IN	Coal	1,336,763,815	1,343,227,931	1,263,538,709	1,231,380,954	
IN	Gas	13,133,977	13,433,549	19,229,684	26,128,241	
IN	Oil	778,970	324,401	76,166	34,611	
MI	All	**803,099,194**	769,855,356	757,546,178	758,577,254	**803,099,194**
MI	Coal	747,647,562	720,117,465	706,851,598	700,052,101	
MI	Gas	28,018,280	28,985,755	30,948,168	43,631,253	
MI	Oil	27,433,352	20,752,136	19,746,412	14,893,900	
OH	All	1,308,156,997	**1,333,059,526**	1,254,434,234	1,322,094,444	**1,333,059,526**
OH	Coal	1,298,547,674	1,325,041,112	1,243,753,980	1,301,135,141	
OH	Gas	9,609,323	8,018,414	10,680,254	20,959,303	
WI	All	508,092,322	**513,589,824**	498,207,479	483,187,294	**513,589,824**
WI	Coal	485,877,284	491,514,817	477,269,081	458,564,604	
WI	Gas	19,343,277	19,214,401	17,848,478	21,649,329	
WI	Wood	2,871,761	2,860,606	3,089,920	2,973,361	
						5,013,814,336

The regional Btu level (5.01 quadrillion Btu) allowed for the determination of the regional NOx budget for IM1 & IM2 and EGU1 & EGU2 by simple multiplying each scenarios proposed NOx emission rate times the regional Btu level. Table 2 illustrates the regional NOx budgets (caps) calculated for each of the IM and EGU scenarios.

Table 2: Regional NOx Budgets by Scenario (tons)

Scenario	NOx Budget
IM1	376,036
IM2	300,829
EGU1	250,691
EGU2	175,484

The next step was an allocation of the regional budget to each of the five states that composed the 5-State Region. The initial task of this step involved determining the average of the 1999 – 2002 Btu (in mmbtu) for Acid Rain and Non-Acid Rain by fuel for each of the five states. These state averages by fuel were adjusted by the CAIR fuel adjustment factors (coal - 1.0, oil - 0.6 and gas – 0.4) and summed to achieve a total adjusted Btu level for each state, as shown in Table 3.

Table 3 – State NOx Budgets for IM and EGU Scenarios (tons)

State Total	Fuel	ADJ BTU	Total ADJ BTU	State Btu Proportion	IM1	IM2	EGU1	EGU2
IL	**All**		**912,761,475**	**0.1907**	**71,699**	**57,360**	**47,681**	**33,460**
IL	Coal	890,081,630						
IL	Gas	21,018,254						
IL	Oil	1,661,591						
IN	**All**		**1,304,365,090**	**0.2725**	**102,461**	**81,969**	**68,138**	**47,815**
IN	Coal	1,294,854,369						
IN	Gas	9,251,452						
IN	Oil	259,269						
MI	**All**		**781,941,042**	**0.1633**	**61,423**	**49,139**	**40,847**	**28,664**
MI	Coal	724,205,284						
MI	Gas	45,233,759						
MI	Oil	12,501,998						
OH	**All**		**1,301,161,363**	**0.2718**	**102,209**	**81,767**	**67,970**	**47,698**
OH	Coal	1,295,963,448						
OH	Gas	5,066,198						
OH	Oil	131,717						
WI	**All**		**486,859,619**	**0.1017**	**38,244**	**30,595**	**25,433**	**17,847**
WI	Coal	478,306,447						
WI	Gas	8,304,634						
WI	Oil	248,538						
WI	**Wood**	0						
			4,787,088,589	**1.0000**	**376,037**	**300,830**	**250,069**	**175,484**

The final task is the allocation of the regional NOx budget to individual states, which is accomplished by multiplying a state's Btu proportion by the regional NOx budget (Table 2) to yield state budget or caps for IM1 & IM2 and EGU1 & EGU2. All heat input data is from U.S. EPA's Technical Support Data used in the final CAIR.

SO2 BUDGET

Initially, the SO2 state budgets for IM1 & IM2 and EGU1 & EGU2 attempted to follow the CAIR allocation process, which is based upon Title IV – Phase II (2010) allocations. However, the stringency of the proposed SO2 emission rates for both the IM and EGU scenarios, coupled with the 1985 – 1987 baseline used for Title IV SO2 allocations, made the caps impossible to achieve in the IM scenarios. Therefore, an alternative allocation was used based upon the average heat input for the years 2000 – 2004 from EPA's CEM data for Acid Rain units. As shown in Table 4, each scenario's SO2 emission rate is multiplied by a state's average heat input (mmbtu) to yield a state's IM or EGU budget/cap.

Table 4 – State SO2 Budgets for IM and EGU Scenarios
(tons)

State	2000 - 04 Ave Btus	IM1	IM2	EGU1	EGU2
IL	985,638,162	177,415	118,277	73,923	49,282
IN	1,241,853,612	223,534	149,022	93,139	62,093
MI	750,342,264	135,062	90,041	56,276	37,517
OH	1,303,918,125	234,705	156,470	97,794	65,196
WI	501,335,732	90,240	60,160	37,600	25,067
REGION	4,783,087,895	860,956	573,971	358,732	239,154
SO2 ER		0.36	0.24	0.15	0.10

APPENDIX B

SUMMARY OF ASSUMPTIONS DEFINING THE FEASIBILITY AND COST OF ENVIRONMENTAL CONTROLS FOR ANALYSIS OF THE MIDWEST RPO MANDATES

INTRODUCTION

Appendix B to this report presents additional detail regarding the assumptions defining the feasibility and cost of environmental control technology. Appendix B serves as the basis of descriptive material that was presented in the final report.

This work consisted of simulating industry decision-making in defining the least cost compliance plan. With approximately 275 units to consider, a limited number of technical options were considered, so as to bound the nature of the problem. However, the limited options represent in general the type of equipment and costs encountered.

As an example, it is well known that many choices exist from which to select flue gas desulfurization technology. A recent review has overviewed the features of different categories of control equipment, identifying the characteristics unique to each (EPA, 2000). However, for the purpose of this analysis, only one option – wet conventional limestone-based FGD – was evaluated. This assumption should not be interpreted to suggest that only this technology is viable for power producers within the Midwest RPO; in fact a broad range of equipment should be considered. However, given that most options exhibit similar incurred cost after levelizing both capital and operating cost, selecting one approach is essential to bounding the problem, and is not believed critical to the outcome.

Similarly, with respect to NOx, two control options were considered – selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR). The use of SNCR was included to provide an alternative option to capital-intensive, high NOx removal SCR. In reality, there are a number of technologies that exhibit the low capital cost, low-moderate NOx removal typical of SNCR. These include both natural gas and coal reburn, and several variants of these processes (e.g. NOxStar). In the context of the present analysis, we submit it is important to offer a feasible alternative to SCR – thus SNCR is considered a "surrogate" for the numerous alternatives. Accordingly, although the site-specific decisions at any one plant may differ from those predicted by this study, the number of installed SCR options versus low capital cost alternatives is anticipated to be correct.

The specific control equipment used in the analysis, and a description of assumed performance and cost, is presented in the following sections for control of SO_2 and NOx.

FLUE GAS DESULFURIZATION

Selecting the optimal process for any given site requires a detailed engineering analysis, beyond the scope of the present study. Accordingly, conventional limestone, forced oxidized flue gas desulfurization was selected as a "surrogate" of the candidates.

The SO_2 removal efficiency was assumed to depend on the coal sulfur content. Specifically, the "baseline" design specified an SO_2 removal efficiency of 90 and 95% was assumed achievable for application to PRB and medium-high sulfur coals, respectively. In addition to this "baseline" design, a "high performance" option was included that allowed extracting up to 97% SO2 removal, for a modest capital and operating cost premium.

The main source of cost information for conventional limestone-based FGD is an analysis prepared for Cinergy Corporation in planning future FGD capacity. This analysis contains data from existing units, and projections based on detailed engineering studies of FGD equipment. These estimates, shown in Figure 1, generally exceed the projections that can be derived using the EPA-issued cost spreadsheet "CUECost" (Keeth, 1999).

Regarding operating costs, Fixed O&M was assumed to be equivalent to 5% of the capital requirement, incurred annually. Variable O&M costs were selected from Table 1, developed from CUECost, which summarizes variable O&M for the three categories of coal. The subject Midwest RPO analysis invoked these variable costs from a lookup table, pending definition of the coal type.

Table 1 summarizes the SO2 removal efficiency assumed, by coal composition, and the operating penalty in terms of power consumption as a percent of generating capacity.

Table 1 - Wet FGD Variable O&M (mills/kWh)

Coal Type (by Sulfur content)	Variable O&M (mills/kWh)	SO2 Removal: Baseline Design	Capacity Penalty (% of capacity)[5]	Energy Penalty (% of capacity)
PRB	0.69	90	1.40	1.5
Medium Sulfur	1.05	95	1.7	1.5
High Sulfur	1.89	95	2	1.5

For new FGD equipment, a high performance option was defined that extracted higher SO2 removal for a premium in capital and operating cost. The baseline design targets of 90 and 95% could be increased to 94 and 98% for an additional $2/kW capital, and 0.20 to 0.25 mills/kWh increase. Table 2 summarizes these options.

[5] Derived from Sargent & Lundy, 2003

Figure 1 - FGD Capital Cost Estimates

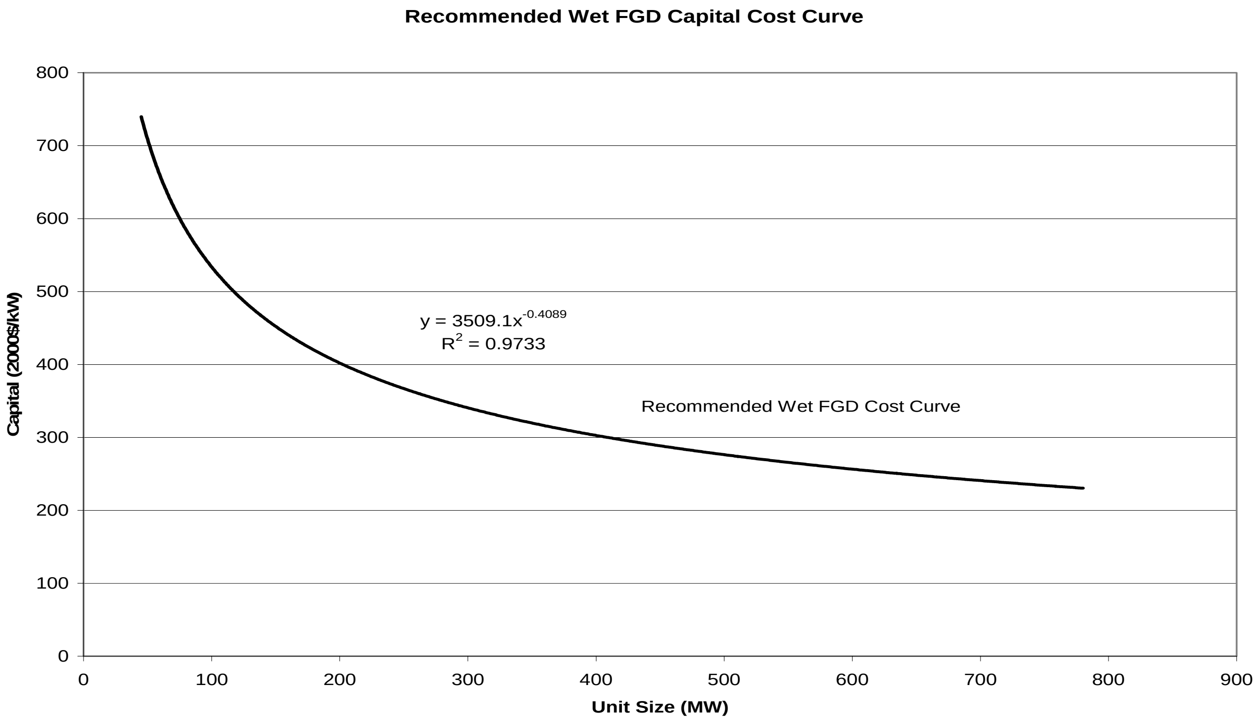


Table 2 - New FGD High Performance SO2 Removal Option

SO2 Removal Increment	SO2 Removal,%	Capital Adder ($/kW)	Var O&M (mills/kWh)
PRB	To 94%	2	0.20
Med-High S coal	To 98%	2	0.25

There are numerous existing FGD processes in operation by Midwestern power producers, and the prospect of upgrading existing equipment to improve performance has been discussed by numerous investigators such as Froelich (1995), Maller (2003), and Doptoka (2003). As these investigators note, the technical feasibility of FGD upgrade is site-specific; depending on the nature of the site or the composition of the coal, only negligible improvement to SO2 removal could be realized. However, for the purpose of this study, it was assumed that upgrade was feasible; it is important to recognize this is an assumption that was not based on specific analysis.

Table 3 summarizes the assumptions defining the potential ability to upgrade existing FGD process equipment. In the content of this study, it is assumed the performance of both venturi-type equipment and conventional open spray towers can be improved.

- All FGD technologies are assumed to be able to deliver a minimum of 93% SO2 removal,
- A capital charge is incurred for a detailed engineering study, including physical cold flow model, upgrade to reagent slurry pumps, and perhaps wall rings to reduce leakage,

- An operating cost increase is incurred, to provide for both greater reagent quantity, and the use of a buffering additive.

Table 3 - FGD Upgrade Assumptions

SO2 Removal Increment	**70->93**	**80→93**
Capital ($/kW)	15	10
Operating cost (mills/kwh)	0.25	0.15

The analysis conducted for Midwestern power producers used this information to evaluate the cost of conventional FGD for various coals, and the prospect of deriving additional SO2 reductions by upgrading process equipment.

NITROGEN OXIDES

There is a wide variety of NOx control options that can be applied at a coal-fired power station, considering technology both presently available and evolving. For the purpose of the present analysis, the post-combustion options considered were limited to SCR, and a lower capital cost alternative, SNCR. As stated in the Introduction, the selection of a limited number of options should not be interpreted as an endorsement of any particular technology; specifically SNCR is not the sole alternative to SCR. Rather, SNCR should be considered a surrogate of a variety of lower capital cost, lower NOx removing options.

Combustion Controls

Prior to being considered for retrofit of post-combustion controls, each unit was evaluated to determine if additional NOx removal by combustion controls was appropriate. Table 4 describes the performance and cost of both low NOx burners (LNB) and over-fire air (OFA). For each unit, the reported 2003 NOx emissions were compared to the NOx rates in Table 4, which are considered to represent the NOx emissions of a unit equipped with state-of-art combustion controls. In cases where the reported NOx emissions exceed these rates, the appropriate combustion modifications were assumed to be retrofit.

Table 4 - Summary of Combustion Control Assumptions

Boiler Type	LNB	LNB+OFA	LNB	LNB+OFA	LNB	LNB+OFA	LNB	LNB+OFA
	High S bit		*Low-Med S bit; Low S East.*		*Low S West*		*PRB*	
tangential	0.4	0.38	0.38	0.36	0.35	0.32	0.22	0.18
front	0.45	0.43	0.43	0.4	0.37	0.32	0.3	0.25
opposed	0.45	0.43	0.43	0.4	0.37	0.32	0.3	0.25
cell	0.68	0.62	0.62	0.57	0.55	0.5	0.48	0.45
wet-bottom	0.86	N/A	0.8	N/A	N/A	0.65	N/A	0.5
cyclone	N/A	1.5	N/A	0.95	N/A	0.65	N/A	0.55

The combustion control technologies described in Table 4 were applied to units according to the following criteria:

- LNB were applied to units greater than 20 MW that were not previously equipped with any combustion controls,
- Units with LNB adopted OFA, for a capacity factor > 25% and generating capacity > 100 MW
- post-1972 NSPS units were assumed to derive an additional 0.02 lbs/MBtu reduction, beyond that defined feasible in Table 4

The cost for LNB and OFA equipment was derived as follows:

- LNB costs were $7/kW for a 500 MW unit, scaled from 100-600 MW capacity with a 2/3 power-law
- OFA costs were $10/kW for a 500 MW unit, scaled from 100-600 MW with a 2/3 power law
- Cyclone boilers adopted OFA alone at $5/kW

In general, almost all units applied some type of combustion control prior to considering post-combustion strategies.

SNCR

Table 5 presents the assumptions defining the performance and cost for SNCR NOx control. As shown, both the NOx removal efficiency achievable, and capital/operating cost vary as function of initial NOx rate. The data in Table 5, particularly for larger units, is based on recent demonstrations on large capacity units (Hines, 2003). The SNCR cost data is based on public references, and is consistent (although not exactly the same) as derived in CUECost.

SCR

SCR capital and operating cost are presented in Tables 5 and Figure 2. Table 5 presents fixed and variable operating cost, as a function of boiler type, and initial NOx rate. Figure 2 presents the derived relationship between SCR capital cost and generating capacity. Basic process design factors such as boiler NOx rate entering the SCR process and the design NOx removal efficiency are well-known to influence the catalyst volume and replacement rate. However, the cost impact of these factors can be super-ceded by site – specific factors that affect the amount of labor required for retrofit; according only generating capacity is used to express capital cost in this relationship.

Figure 2 depicts an inferred relationship between SCR capital cost and generating capacity. This relationship was derived based on a survey of actual SCR costs incurred by domestic U.S. power producers (Cichanowicz, 2004). For the purposes of this study, the SCR capital cost of any given unit is determined by the value derived from the correlation in Figure 3.

Table 5 - SNCR NOx Removal, Operating Cost

Capacity (MW)	**Burner Firing Type** t-tangential; f- front-fired; o - opposed fired	**Initial Boiler NOx** (lbs/MBtu)	**Conventional SNCR** SNCR ($/kW)	SNCR O&M ($/MWh)	NOx Removal (%)
>500	t-f-o	0.20-0.30	10.0	0.35	25
	t-f-o	0.31-0.40	"	0.48	25
	t-f-o	0.40-0.50	"	0.58	25
	t-f-o	>0.50	"	0.63	25
	cell	<0.65	16	0.74	28
	"	>0.65	16	0.89	28
	cyclone/wet-bottom	<0.86	16	0.95	30
	"	>0.86	16	1.22	30
400-500	t-f-o	0.20-0.30	11	0.35	25
	t-f-o	0.31-0.40	"	0.48	25
	t-f-o	0.40-0.50	"	0.58	25
	t-f-o	>0.50	"	0.63	25
	cell	<0.65	13	0.74	28
	"	>0.65	13	0.89	28
	cyclone/wet-bottom	<0.86	13	0.95	30
		>0.86	13	1.22	30
300-400	t-f-o	0.20-0.30	13	0.35	27
	t-f-o	0.31-0.40	"	0.48	27
	t-f-o	0.40-0.50	"	0.58	27
	t-f-o	>0.50	"	0.63	27
	cell	<0.65	15	0.74	30
	"	>0.65	15	0.89	30
	cyclone/wet-bottom	<0.86	15	0.95	32
	"	>0.86	15	1.22	32
200-300	t-f-o	0.30-0.40	16	0.35	30
	t-f-o	0.41-0.50	"	0.48	30
	t-f-o	>0.50	"	0.58	30
			"	0.63	30
	cell	<0.65	18	0.74	
	"	>0.65	18	0.89	33
	cyclone/wet-bottom	<0.86	18	0.95	33
	"	>0.86	18	1.22	33
126-200	t-f-o	<0.40	22	0.35	33
	t-f-o	0.40-0.50	"	0.48	33
	t-f-o	>0.50	"	0.58	33
	cell	<0.65	24	0.74	36
	"	>0.65	24	0.89	36
	cyclone/wet-bottom	<0.86	24	0.95	36
	"	>0.86	24	1.22	36
75-125	t-f-o	<0.40	29	0.35	36
	t-f-o	0.40-0.50	"	0.48	36
	t-f-o	>0.50	"	0.58	36
	cell	all	"	0.9	40
	cyclone/wet-bottom	all	"	0.9	40
20-74	all		35	0.9	45

Table 6 presents SCR operating and maintenance costs as a function of boiler inlet NOx rate, showing both variable and fixed O&M.

Table 6 - Summary of SCR Variable, Fixed Operating and Maintenance Costs

Note: NOx removal will be either 90%, or limited to the NOx emissions rates shown in the below table

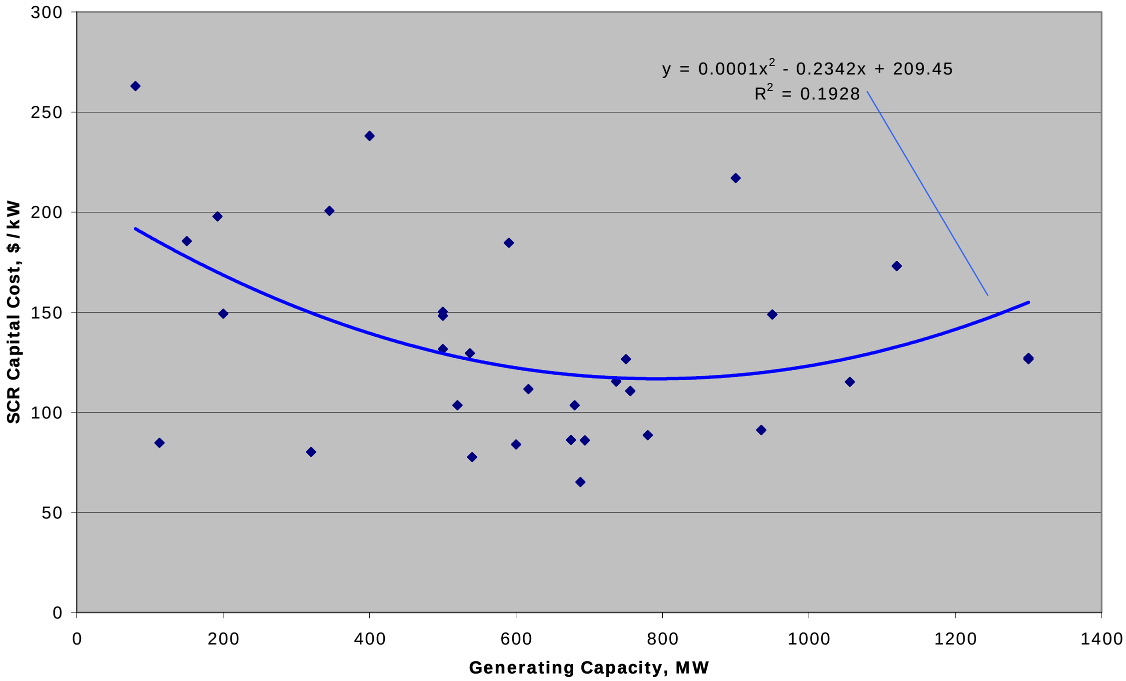
Initial Boiler NOx (lbs/MBtu)	SCR O&M Variable ($/MWh)	SCR Fixed O&M (% of Capital /yr)
0.3	0.59	0.75
0.4	0.63	0.75
0.5	0.75	0.75
0.6	0.78	0.75
0.7	0.91	0.75
0.8	1.05	0.75

NOx Outlet Rates Achievable

Coal Type	NOx Out
PRB	0.045
Sub (<1.2%)	0.05
1.2-2.5	0.06
high S >2.5	0.07

The SCR long-term continuous NOx removal efficiency was assumed to be 90 percent; however, NOx emission rate floors were established based upon coal rank. These floors, which determine the minimum a final SCR controlled level, are shown on the right side of Table 6. These floors are 0.07 lbs/MBtu MBtu for low (<1.2%) sulfur sub-bituminous coal, and 0.045 lbs/MBtu for PRB. It is important to note these NOx targets are for annual averaging periods; shorter averaging periods will likely be characterized by higher SO2 emission rates. For example, a 30 day NOx emissions average for high sulfur bituminous coal could be 0.08 lbs/MBtu.

Figure 3. SCR Capital Cost vs. Capacity (w/Engineering/AFDC)



COAL SWITCHING

One control strategy considered in this analysis was the potential to switch coals, from medium-high sulfur to lower sulfur content, including coals from the PRB. This section summarizes the two factors used in the fuel switching analysis; the capital cost for the plant modifications to accommodate the switch, and the cost of the alternative coal.

Two types of fuel switching were considered as a part of evaluating SO2 compliance options, which considered differential coal prices. These are summarized as follows:

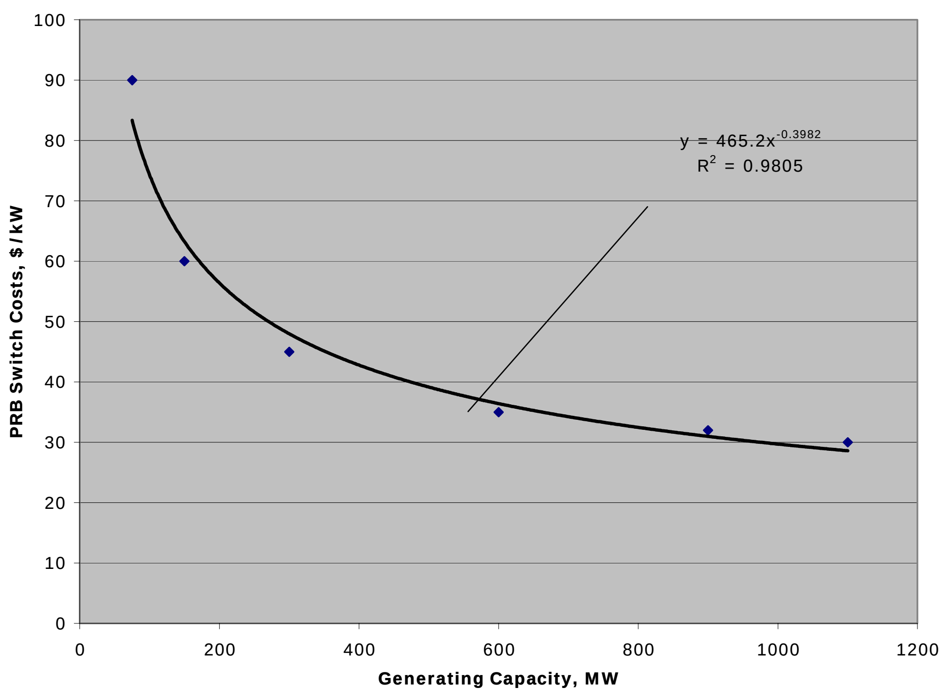
- Switching from a higher sulfur bituminous coal to a low sulfur sub-bituminous (PRB) coal, to avoid FGD, and
- Determining the optimal combination of FGD and coal type, by considering both FGD O&M cost for each of sub-bituminous (PRB), and medium or higher sulfur bituminous coal.

Coal Switch Capital Costs

The broad availability of PRB has prompted many operators to consider switching to PRB and other low sulfur coals. The use of PRB coal will impacts almost all aspects of operating a power plant, and is contemplated only after detailed engineering studies defining the impacts (Power, 2003). A coal switch to PRB from either medium or high sulfur coal usually requires capital investment to maintain thermal performance and minimize capacity de-rate. Several operators that are contemplating or have already switched to PRB coal provided input as to capital cost estimates for PRB conversion.

Of the coal switch options considered in this study, only a switch to PRB required capital investment. Figure 4 presents the relationship between capital cost to accommodate PRB coal and generating capacity, as determined from the survey of operators.

Figure 4. PRB Switch Costs vs. Capacity



Alternative Coal Costs

This analysis considered three sources of coal – PRB, medium sulfur from the Eastern Interior region, and high sulfur from the Eastern interior region. Table 7 summarizes the heating value and sulfur content of the coals that were used to represent these three different classes of options. Table 8 presents the cost of each coal, expressed on a 2003 dollar basis, over the time period of the analysis. The coal prices in Table 8 were derived from EIA's *Annual Energy Outlook 2005 (AEO 2005)*.

Table 7 - Characteristics Of Coals From Alternative Sources

Coal Characteristic	PRB	Medium sulfur	High Sulfur
Sulfur content, %	0.30	1.2	3.0
Heating Value (Btu/lb)	8,700	10,518	11,082

Table 8 - Delivered Coal Prices: 2010 - 2015

Census Region	Supply Region	Supply Region States	SO2 ER	2010	2011	2012	2013	2014	2015
East North Central	CA	S.WV,VA,E.KY,N.TN	Low (1.2 or less)	1.41	1.39	1.37	1.38	1.39	1.40
East North Central	CA	S.WV,VA,E.KY,N.TN	Medium (>1.2 - 3.33)	1.36	1.47	1.43	1.45	1.44	1.30
East North Central	EI	W.KY,IL,IN,MS	High (>3.33)	1.13	1.12	1.12	1.11	1.12	1.13
East North Central	NA	PA,OH,MD,N.WV	High (>3.33)	1.08	1.08	1.12	1.12	1.13	1.13
East North Central	PRB WY	WY Powder River Basin	Low (1.2 or less)	1.13	1.13	1.13	1.13	1.13	1.13

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APPENDIX C

REPLACEMENT CAPACITY POWER COSTS, STATE LEVEL COMPLIANCE COSTS AND LOCAL COAL DISPLACEMENT

The focus of this appendix briefly discusses the methodology to determine the replacement power costs and local coal displacement. It also presents IM and EGU compliance costs by state.

REPLACEMENT POWER COSTS

As mentioned in the text, replacement power for those units that would be retired under EGU1 and EGU2 would be supplied by three sources and they are: (i) increased operation of existing (2013) gas-fired combined cycle capacity in ECAR, MAIN and MAPP; (ii) imported power from surrounding NERC regions; and, (iii) the construction of new gas-fired combined cycle capacity in the affected NERC regions. It was assumed the replacement power or electrical demand would be initially supplied by existing capacity and then followed by imported power. Only after, these two components achieved maximum capability would new units be constructed.

The table below illustrates the level of nameplate capacity and generation that would have to be replaced under EGU1 and EGU2 within the five states for year 2013. The data is presented by NERC region because some states contain two NERC regions and any electricity to be supplied to these five states would have to be supplied through a grid based upon a NERC region.

Table 1 – Replacement Power Requirement: 2013

EGU1	MW	Generation (kWh)
ECAR	7,867.5	44,959,822,101
MAIN	2,680.3	15,271,658,743
MAPP	82.4	433,094,400
	10,630.2	60,664,575,244
EGU2		
ECAR	20,744	120,170,934,587
MAIN	13,578.6	72,548,970,003
MAPP	586	353,9571,115
	34,908.6	196,259,475,705

Existing Gas-Fired Combined Cycle Capacity

The first component of replacing this lost power was increasing the operation of existing gas-fired combined cycle capacity. In 2013, there was a projected availability of 3,785 MW in ECAR and 2,167 MW in MAIN of exiting combined-cycle capacity that could be used to supply additional generation, as shown in Table 2. It as assumed the replacement power for MAPP could be entirely achieved through imports; therefore, no existing generation would come from existing combined cycle capacity.

Table 2 – Replacement Power from Existing Combined Cycle: 2013

	Available CC Capacity (MW)	Generation Supplied (kWh)	Cost of Incremental Generation (2003$)
EGU1			
ECAR	3,485	30,532,279,200	1,275,027,979
MAIN	2,167	15,271,658,743	637,744,469
MAPP			
Total Cost			1,912,772,448
EGU2			
ECAR	3,485	30,532,279,200	1,275,027,979
MAIN	2,167	18,979,328,400	792,576,754
MAPP			
Total Cost			2,067,604,733

The assumed incremental cost for fuel (natural gas) in 2013 is $5.55/mmbtu and variable O&M costs are 1.8 mills/kWh. The future gas price is based upon a comparison of natural gas price forecasts, while the variable O&M is based upon EIA's *AEO2005* performance costs of new generating technologies.

Imported Power

The second component of replacing power would come from importing power from neighboring NERC regions, which in this case would be primarily from MAAC, SERC and SPP. Based upon data from EIA and NERC on regional transmission capability and 2013 imports into ECAR, MAIN and MAPP, the table below illustrates the assumed 2013 import capability into ECAR, MAIN and MAPP.

Table 3 – Region to Region Transmission Capability: 2013
(MW)

Import Region	Import Capability and Export Regions
ECAR	8,233 from MAAC and SERC
MAIN	3,386 from SERC and SPP
MAPP	3,300 from SERC, SPP, NWP and RA

Table 4 indicates the level of power imported from neighboring regions and the cost of the imported power.

Table 4 – Replacement Power from Imported Power: 2013

	Imported Capacity (MW)	Imported Generation (kWh)	Cost of Imported Power (2003$)
EGU1			
ECAR	1,646.98	14,427,542,901	591,529,259
MAIN	0	0	0
MAPP	49.44	433,094,400	16,457,587
Total Cost			607,986,846
EGU2			
ECAR	8,233	72,121,080,000	2,956,964,280
MAIN	3,386	29,661,360,000	1,127,131,680
MAPP	404.06	3,539,571,115	134,503,702
Total Cost			4,218,599,662

The cost of imported power was based upon the exporting region's 2013 generation costs (cents/kWh) that were estimated in *AEO2005*.

New Gas-Fired Combined Cycle Capacity

The final component of the replacement power equation is building new gas-fired combined cycle capacity. Only EGU2 required new gas-fired capacity to be constructed, EGU1 was able to meet its electrical demand through increased operation of existing combined cycle capacity and importing power from neighboring regions. Table 5 illustrates the level of replacement power that will be supplied by new natural gas-fired combined cycle capacity.

Table 5 – Replacement Power from New Gas-Fired Combine Cycle Capacity EGU2: 2013

EGU2	New Gas Capacity - Nameplate (MW)	New Gas-fired Generation (kWh)	Total Cost of New Gas-fired Generation (2003$)
ECAR	3,926.73	17,517,575,387	957,236,781
MAIN	5,359.27	23,908,281,603	1,306,452,863
MAPP	0	0	0
Total Cost			2,263,689,644

The assumptions for capital and fixed & variable O&M costs for the new capacity were from EIA's *AEO2005* performance costs of new generating technologies. The 2013 natural gas price was the same $5.55/mmbtu used to determine the incremental cost for existing gas capacity.

It should be noted the previous discussed calculations do not take into account the production and fuel costs of the coal-fired units they are replacing. A final step of this methodology was to net out these costs, which presents a more accurate incremental (or net) compliance costs of EGU1 and EGU2. The table below illustrates both the gross and net replacement costs for EGU1 and EGU2, with the net cost value being the more accurate compliance value used in computing the total compliance costs for EGU1 and EGU2.

Table 6 – Gross and Net Replacement Power Costs
(2003$)

	EGU1(2013)	EGU2(2013)
Cost	Replacement Power	Replacement Power
Gross	2,520,734,431	8,549,847,800
Net	1,359,639,479	4,916,840,764

STATE LEVEL COMPLIANCE COSTS FOR IM AND EGU SCENARIOS

The compliance costs presented in the main text illustrate costs at the regional or five state levels. The purpose of this section is to illustrate these same compliance costs, but present them at the state level. Table 7 illustrates the annualized compliance costs by state for IM1 & IM2 and EGU1 & EGU2.

Table 7 – Annualized Compliance Costs by State
(2003$)

State	IM1(2012)	IM2(2012)	EGU1(2013)	EGU2(2013)
IL	141,908,552	645,616,218	1,048,153,282	1,660,341,178
IN	622,442,301	873,103,743	1,487,854,525	1,949,303,522
MI	353,145,306	584,606,536	695,753,911	1,111,678,216
OH	713,441,471	773,016,589	1,417,768,180	1,640,383,855
WI	204,150,547	302,702,955	345,107,623	711,341,661
Total	2,035,088,176	3,179,046,041	4,994,637,521	7,073,048,432

Table 8 presents breakouts of the EGU1 and EGU2 annualized compliance costs between the net replacement power costs (see Table 6) and SO2 and NOx control technology costs by state.

Table 8 – Compliance Costs to Meet EGU1 and EGU2
(2003$)

	EGU1(2013)			EGU2(2013)		
State	Rep. Power	Technology	Total	Rep. Power	Technology	Total
IL	280,017,300	768,135,982	1,048,153,282	1,255,093,744	405,247,434	1,660,341,178
IN	363,307,377	1,124,547,148	1,487,854,525	1,327,599,129	621,704,393	1,949,303,522
MI	226,643,242	469,110,669	695,753,911	871,410,559	240,267,657	1,111,678,216
OH	446,974,380	970,793,800	1,417,768,180	891,707,099	748,676,756	1,640,383,855
WI	42,697,180	302,410,443	345,107,623	571,030,233	140,311,428	711,341,661
Total	1,359,639,479	3,634,998,042	4,994,637,521	4,916,840,764	2,156,207,668	7,073,048,432

The table above illustrates a shift from control technology to replacement power as compliance becomes more difficult and more coal-fired capacity would have to be retired.

LOCAL COAL DISPLACEMENT

The focus of this analysis was to determine level of coal that is mined in Illinois, Indiana and Ohio that could be displaced as a result of compliance with either EGU1 or EGU2. There are two types of compliance decisions that can impact local coal: (i) retirement of existing coal units; and, (ii) fuel switching existing/retrofitted FGDs from high sulfur coal to PRB coal.

The determination those units that would receive local coal in 2013 was based upon data contained in the *EEMS* Data Base and 2004 reported data from EIA Form 423 and FERC Form 423. The EGU1 and EGU2 model simulations identified those units that could be retired or fuel switched and had these units' 2013 Btus computed. Unit Btus were converted to tons of local coal that could be displaced by an average coal heat content of Illinois (11,655 Btu/lb.), Indiana (11,395 Btu/lb.) and Ohio (12,143 Btu/lb.) coals. The table below illustrates the level of local coal that would be displaced due to compliance with EGU1 and EGU2 in 2013.

Table 9 – Displacement of Illinois, Indiana and Coal: 2013
(tons)

	EGU1			EGU2		
COAL ORIGIN	RETIREMENT	FUEL SWITCH	TOTAL	RETIREMENT	FUEL SWITCH	TOTAL
IL	190,004	5,650,655	5,840,658	4,340,854	2,454,984	6,795,838
IN	2,994,510	15,928,198	18,922,709	13,509,336	8,378,637	21,887,973
OH	3,828,853	14,018,409	17,847,263	5,400,843	13,690,660	19,091,502
TOTAL	7,013,367	35,597,262	42,610,630	23,251,033	24,524,281	47,775,313

Ozone Model Performance: Base J

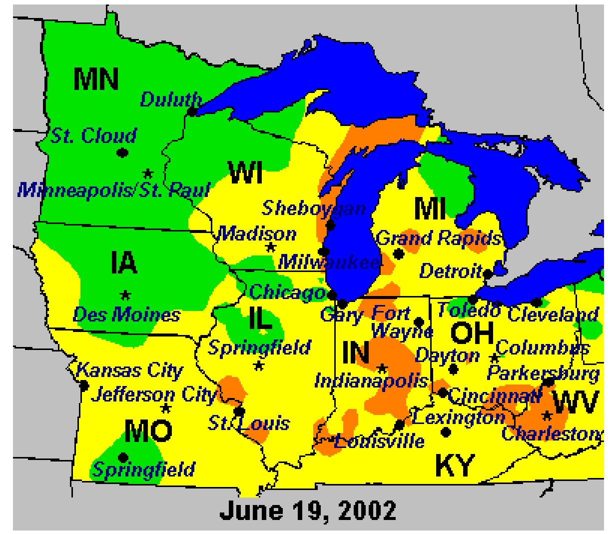
Kirk Baker

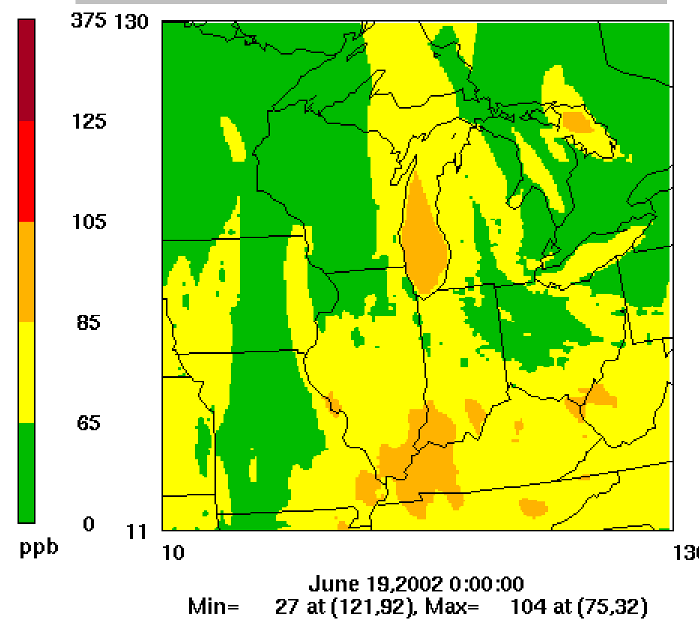
September 2005

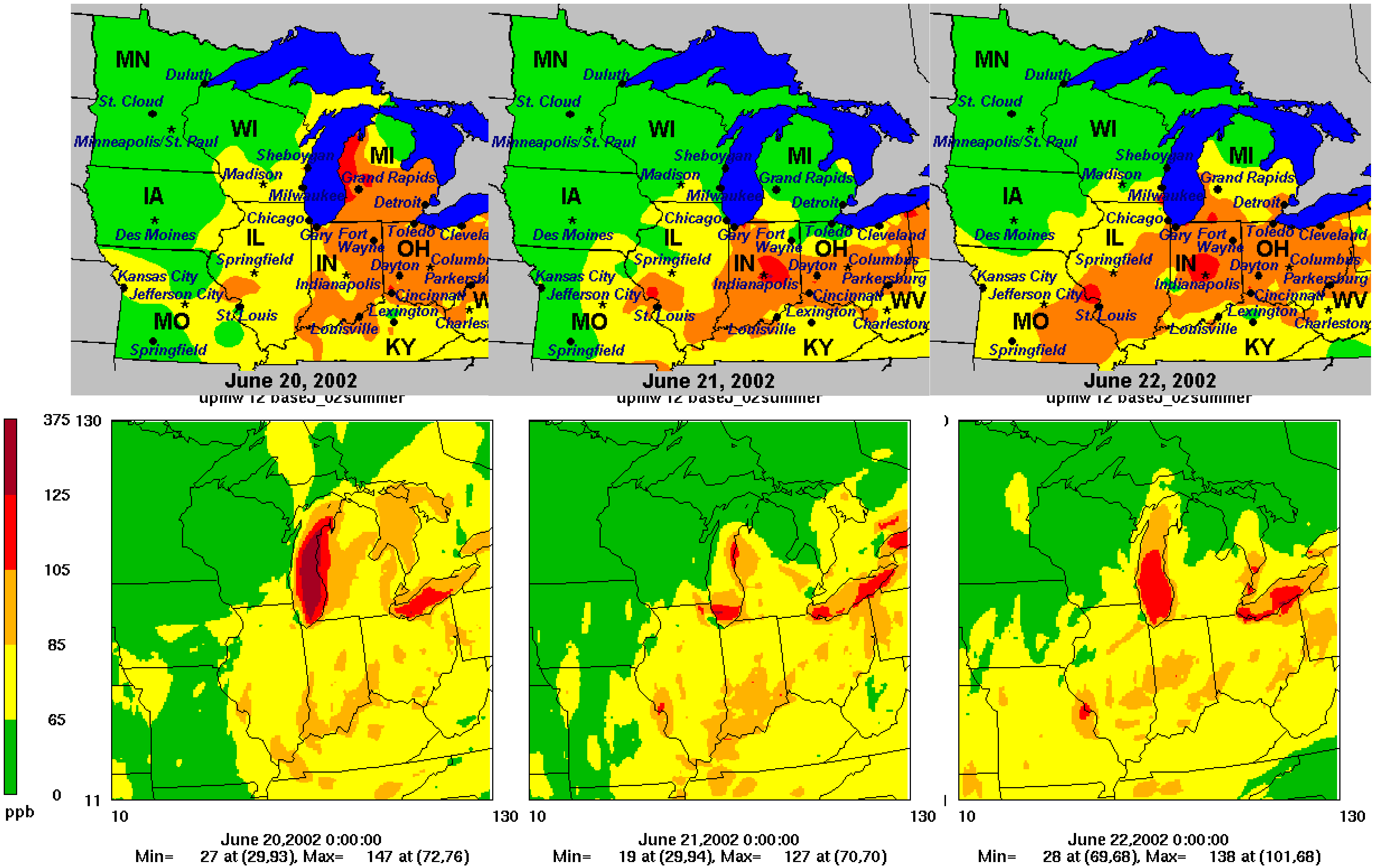
LADCO/MRPO

Spatial Plots

- 8 HR O3
- Daily Peak Plots
- 12 km Base J
- AIRNOW spatial maps of observations



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Fort Wayne
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Des Moines
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Kansas City
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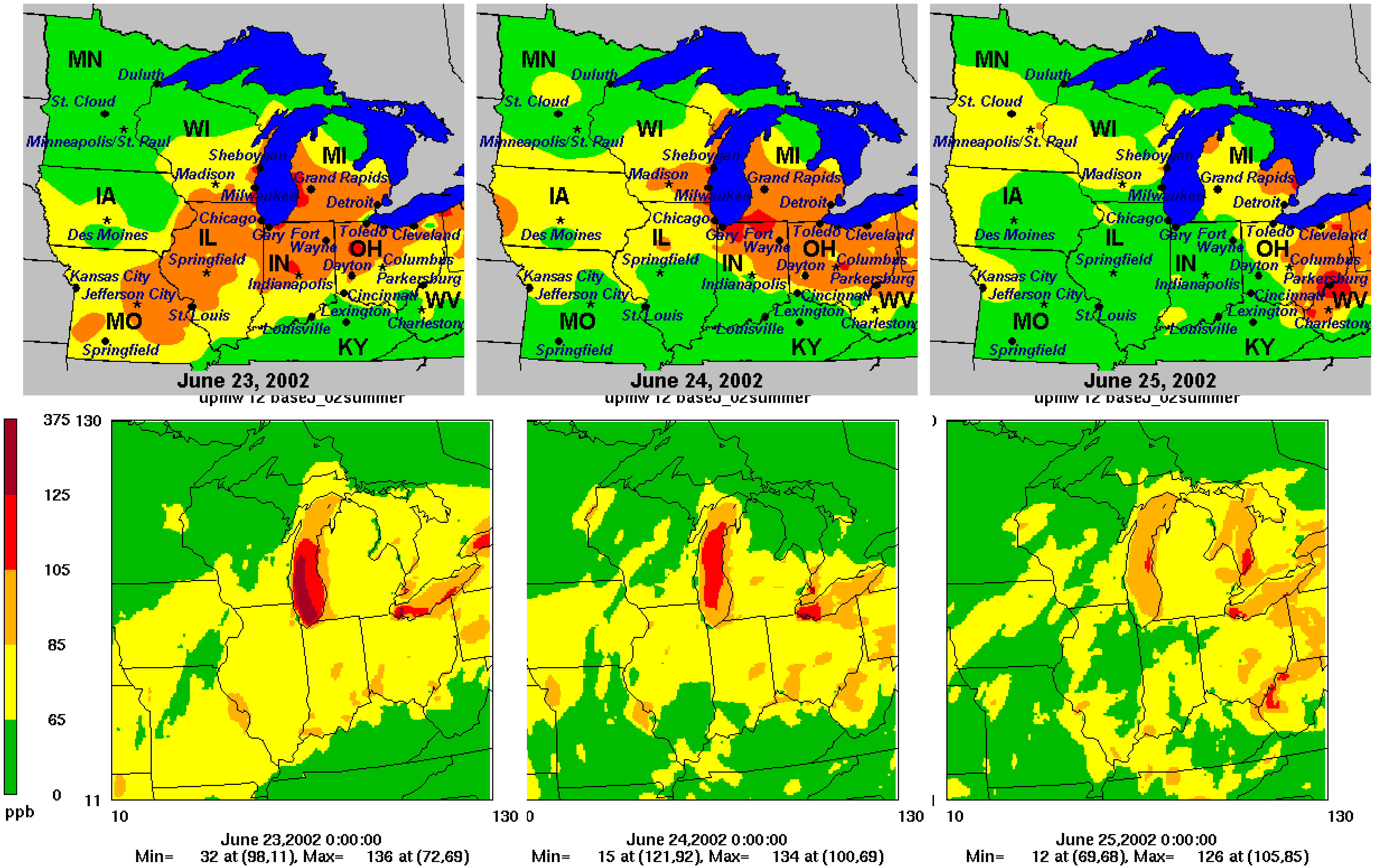
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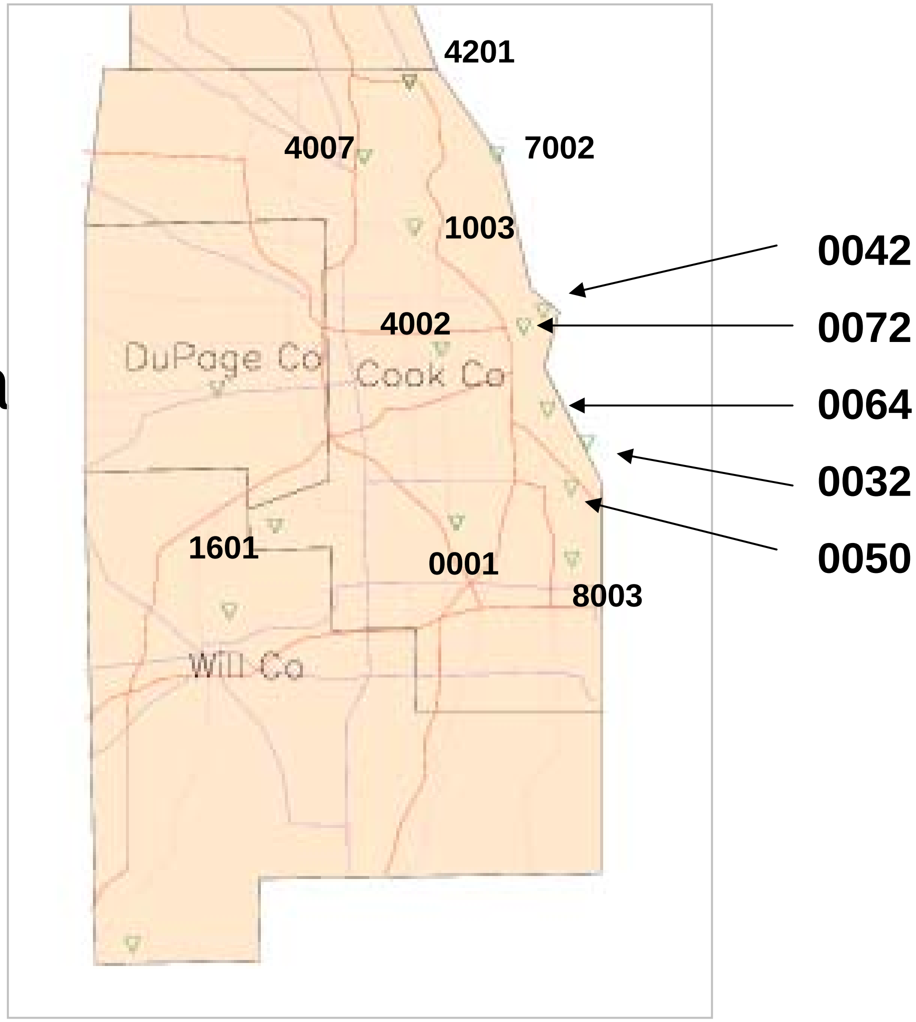
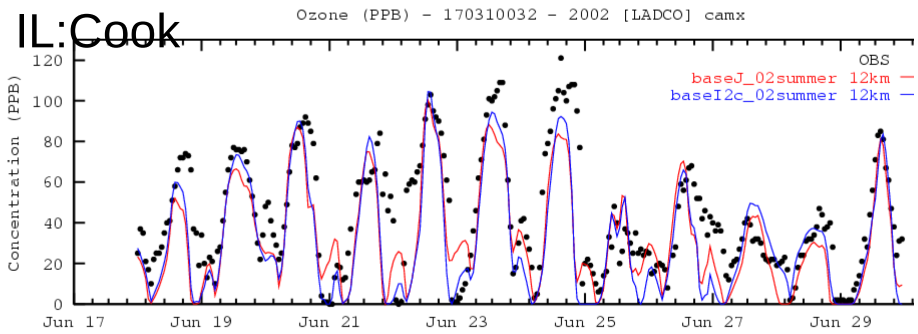
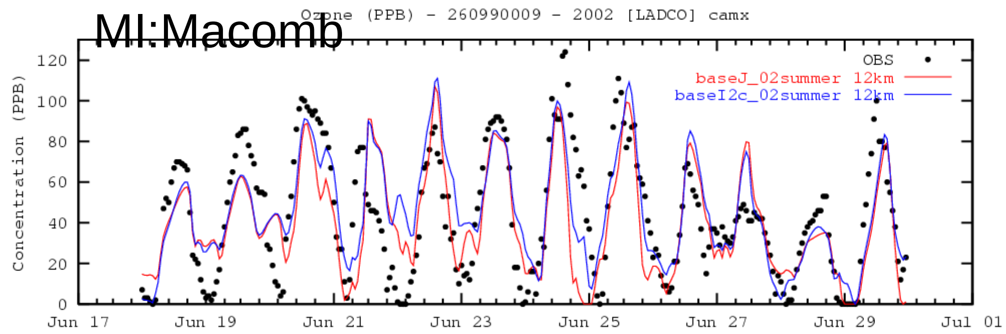
MI
Grand Rapids
Detroit
IA
Des Moines
Chicago
Gary
Fort Wayne
Toledo
Cleveland
IL
Springfield
IN
OH
Dayton
Columbus
Kansas City
Jefferson City
Indianapolis
Parkersburg
Cincinnati
WV
St. Louis
Lexington
MO
Louisville
Charleston
Springfield
KY
June 23, 2002
June 24, 2002
June 25, 2002
upmw 12 baseJ_02summer
375
125
105
85
65
0
ppb
130
11
10
130
June 23,2002 0:00:00
Min= 32 at (98,11), Max= 136 at (72,69)
June 24,2002 0:00:00
Min= 15 at (121,92), Max= 134 at (100,69)
June 25,2002 0:00:00
Min= 12 at (69,68), Max= 126 at (105,85)

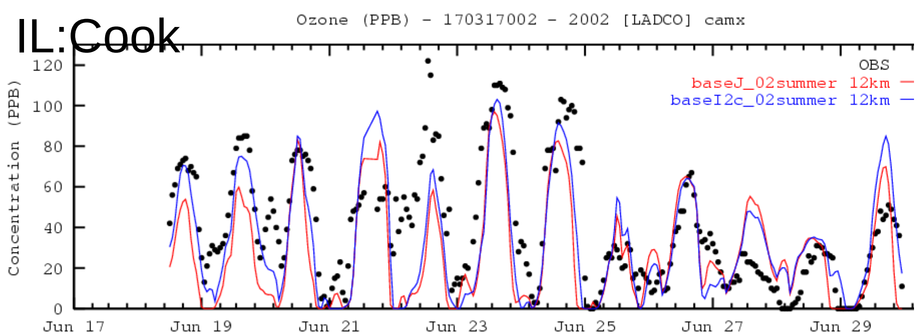
Time Series Plots

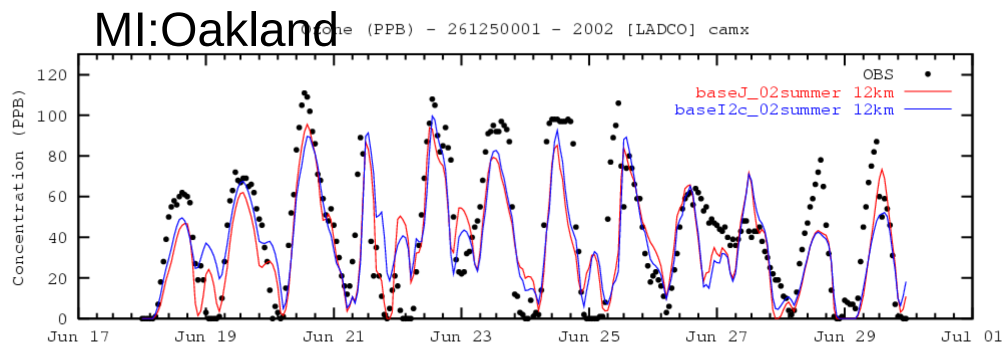
- 8 HR **O3**
- Time-series plots at select monitors
- Monitors selected tha failed the attainment test after R2S2 scenario
- Base J and Base I shown on the plot

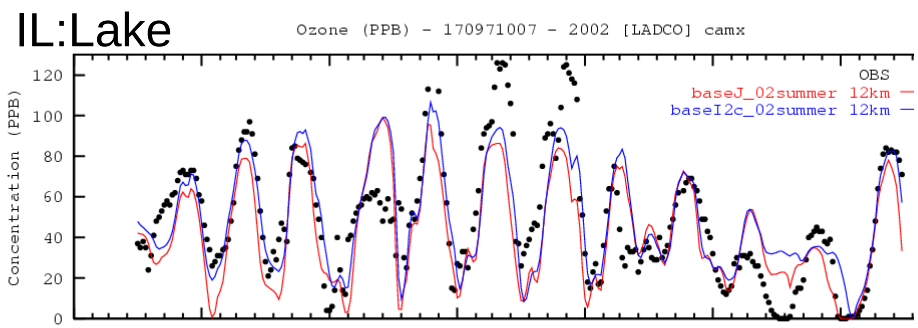


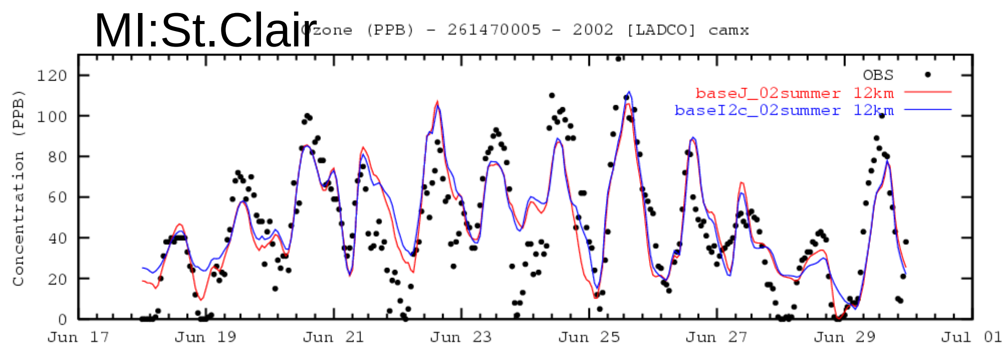

IL:Cook
Ozone (PPB) - 170310032 - 2002 [LADCO] camx
OBS
baseJ_02summer 12km
baseI2c_02summer 12km
Concentration (PPB)
Jun 17
Jun 19
Jun 21
Jun 23
Jun 25
Jun 27
Jun 29

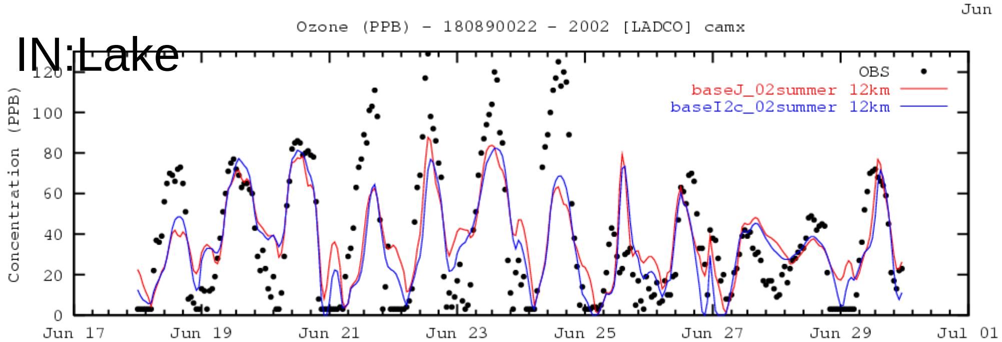

MI:Macomb
Ozone (PPB) - 260990009 - 2002 [LADCO] camx
OBS
baseJ_02summer 12km
baseI2c_02summer 12km
Concentration (PPB)
Jun 17
Jun 19
Jun 21
Jun 23
Jun 25
Jun 27
Jun 29
Jul 01


IL:Cook
Ozone (PPB) - 170317002 - 2002 [LADCO] camx
OBS
baseJ_02summer 12km
baseI2c_02summer 12km
Concentration (PPB)
Jun 17
Jun 19
Jun 21
Jun 23
Jun 25
Jun 27
Jun 29

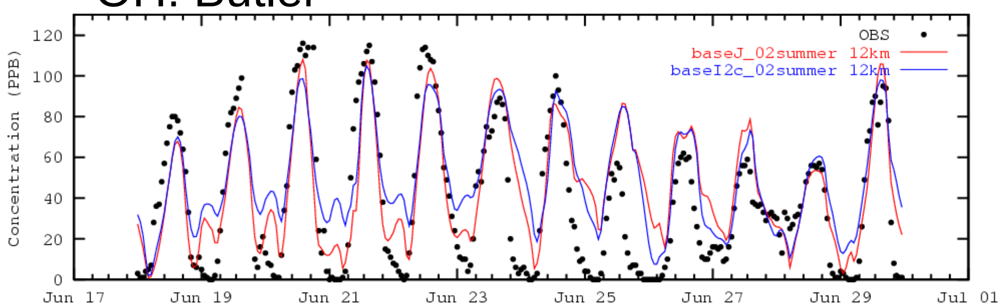

MI:Oakland
Ozone (PPB) - 261250001 - 2002 [LADCO] camx
OBS
baseJ_02summer 12km
baseI2c_02summer 12km
Concentration (PPB)
Jun 17
Jun 19
Jun 21
Jun 23
Jun 25
Jun 27
Jun 29
Jul 01


IL:Lake
Ozone (PPB) - 170971007 - 2002 [LADCO] camx
OBS
baseJ_02summer 12km
baseI2c_02summer 12km
Concentration (PPB)

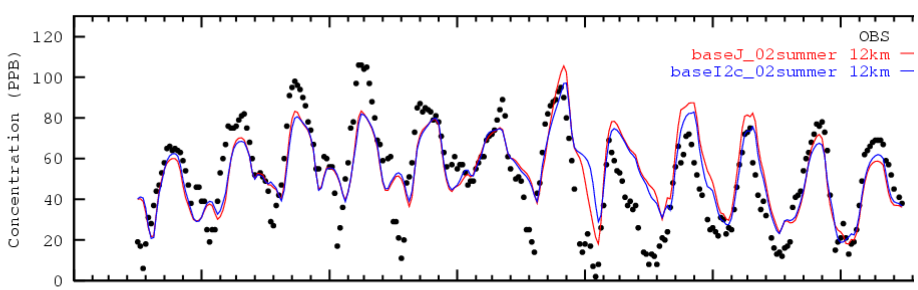

MI:St.Clair
Ozone (PPB) - 261470005 - 2002 [LADCO] camx
OBS
baseJ_02summer 12km
baseI2c_02summer 12km
Concentration (PPB)
Jun 17
Jun 19
Jun 21
Jun 23
Jun 25
Jun 27
Jun 29
Jul 01


IN:Lake
Ozone (PPB) - 180890022 - 2002 [LADCO] camx
OBS
baseJ_02summer 12km
baseI2c_02summer 12km
Concentration (PPB)
Jun 17
Jun 19
Jun 21
Jun 23
Jun 25
Jun 27
Jun 29
Jul 01

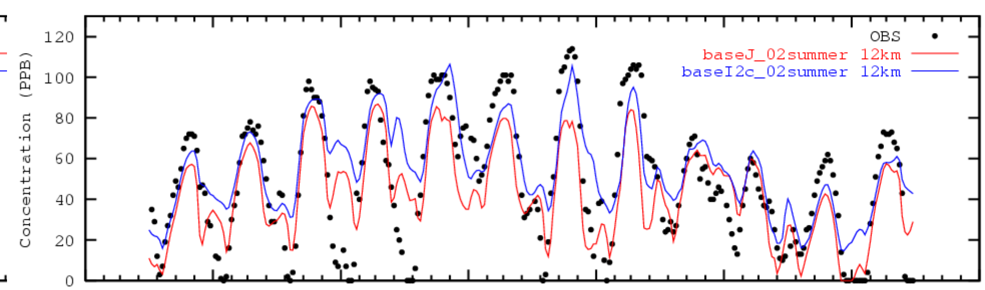
OH: Butler



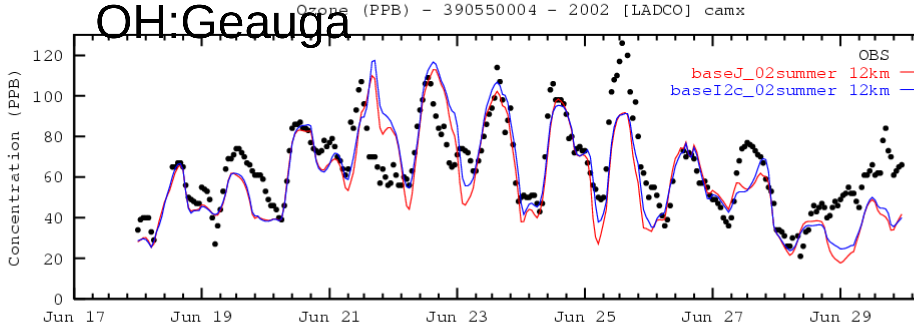
OH:Clinton



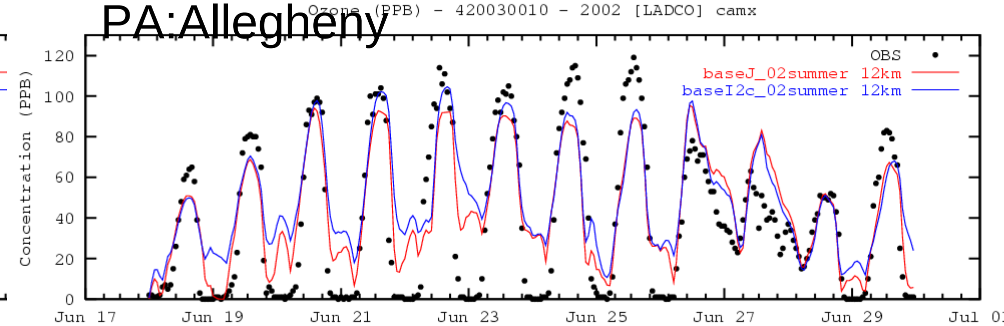
OH:Summit

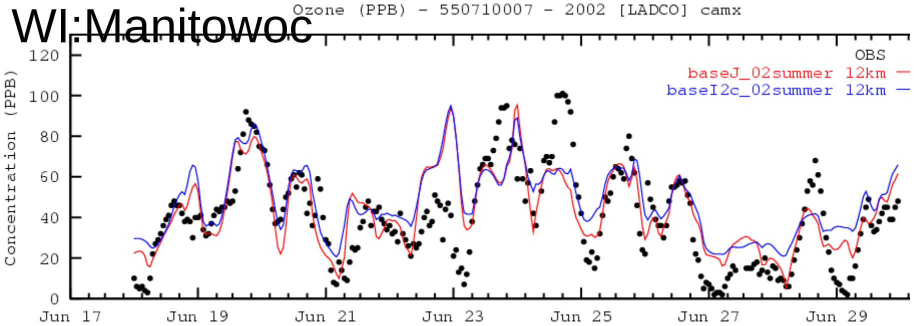


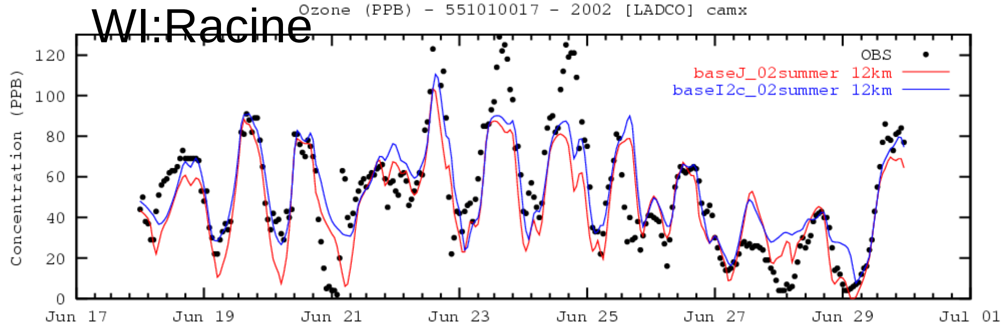
OH:Geauga

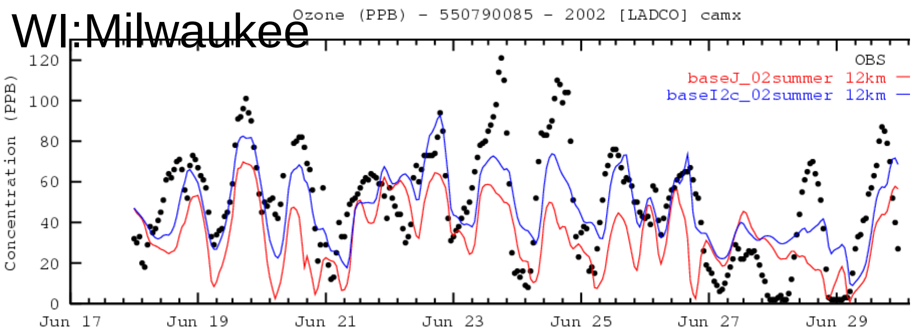


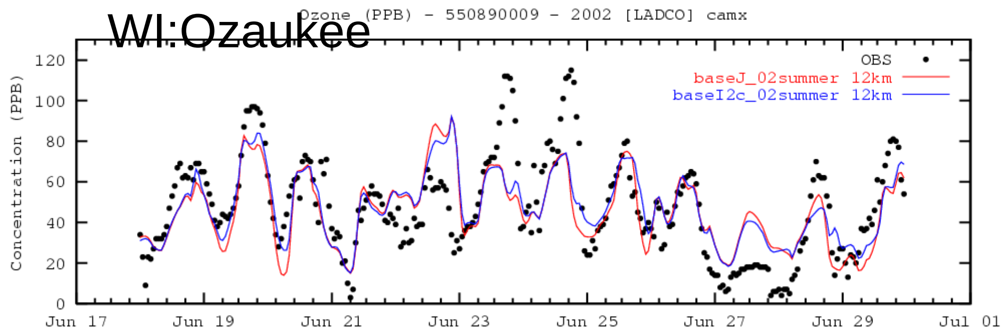
PA:Allegheny

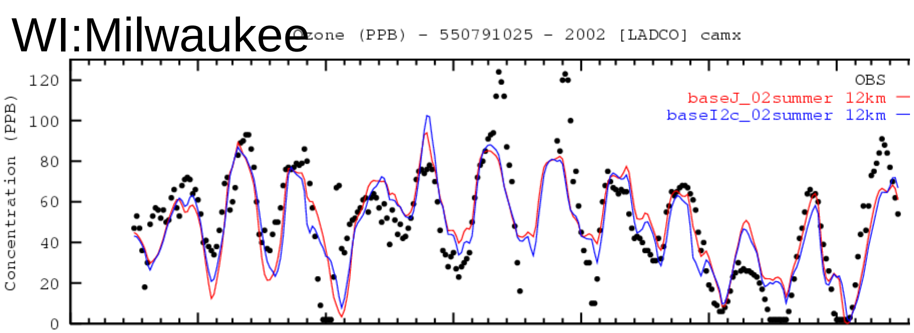


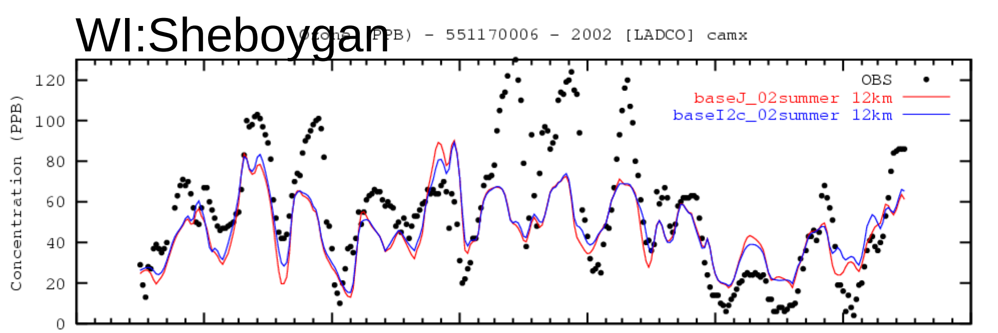

WI:Manitowoc
Ozone (PPB) - 550710007 - 2002 [LADCO] camx
OBS
baseJ_02summer 12km
baseI2c_02summer 12km
Concentration (PPB)
Jun 17
Jun 19
Jun 21
Jun 23
Jun 25
Jun 27
Jun 29

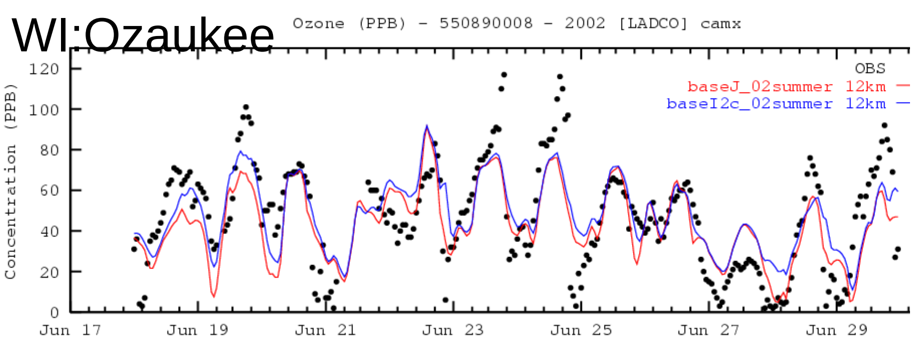

WI:Racine
Ozone (PPB) - 551010017 - 2002 [LADCO] camx
OBS
baseJ_02summer 12km
baseI2c_02summer 12km
Concentration (PPB)
Jun 17
Jun 19
Jun 21
Jun 23
Jun 25
Jun 27
Jun 29
Jul 01

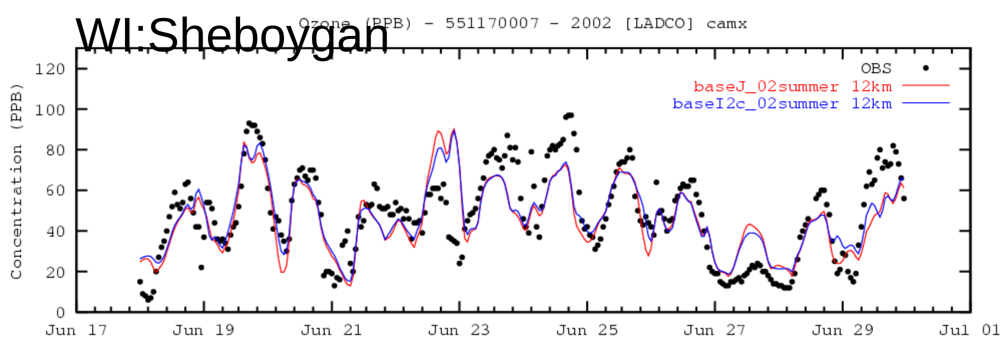

WI:Milwaukee
Ozone (PPB) - 550790085 - 2002 [LADCO] camx
OBS
baseJ_02summer 12km
baseI2c_02summer 12km
Concentration (PPB)
Jun 17
Jun 19
Jun 21
Jun 23
Jun 25
Jun 27
Jun 29


WI:Ozaukee
Ozone (PPB) - 550890009 - 2002 [LADCO] camx
OBS
baseJ_02summer 12km
baseI2c_02summer 12km
Concentration (PPB)
Jun 17
Jun 19
Jun 21
Jun 23
Jun 25
Jun 27
Jun 29
Jul 01

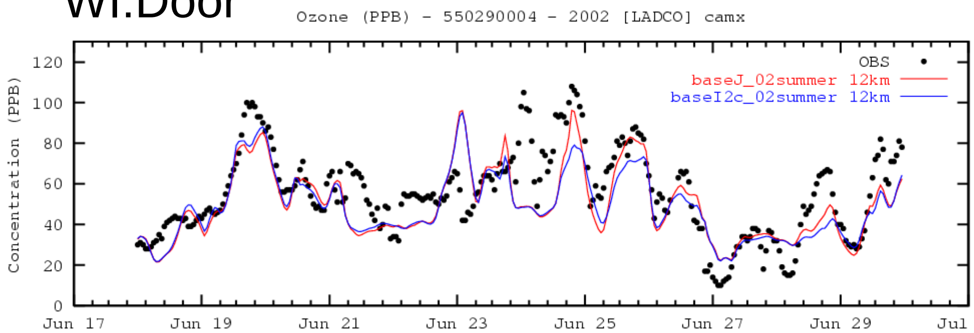

WI:Milwaukee
Ozone (PPB) - 550791025 - 2002 [LADCO] camx
OBS
baseJ_02summer 12km
baseI2c_02summer 12km
Concentration (PPB)


WI:Sheboygan
Ozone (PPB) - 551170006 - 2002 [LADCO] camx
OBS
baseJ_02summer 12km
baseI2c_02summer 12km
Concentration (PPB)

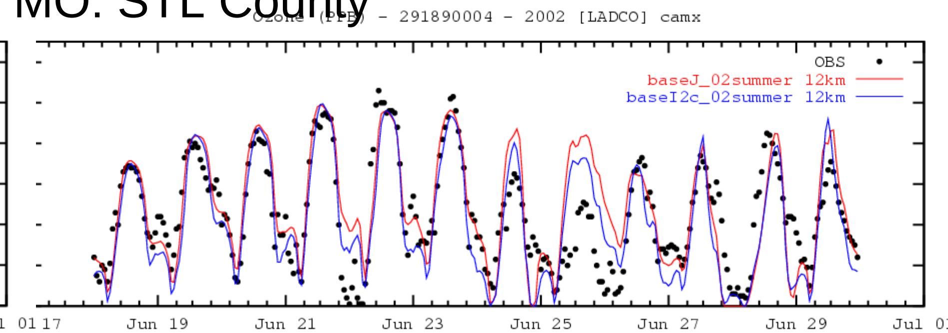

WI:Ozaukee
Ozone (PPB) - 550890008 - 2002 [LADCO] camx
OBS
baseJ_02summer 12km
baseI2c_02summer 12km
Concentration (PPB)
Jun 17
Jun 19
Jun 21
Jun 23
Jun 25
Jun 27
Jun 29


WI:Sheboygan
Ozone (PPB) - 551170007 - 2002 [LADCO] camx
OBS
baseJ_02summer 12km
baseI2c_02summer 12km
Concentration (PPB)
Jun 17
Jun 19
Jun 21
Jun 23
Jun 25
Jun 27
Jun 29
Jul 01

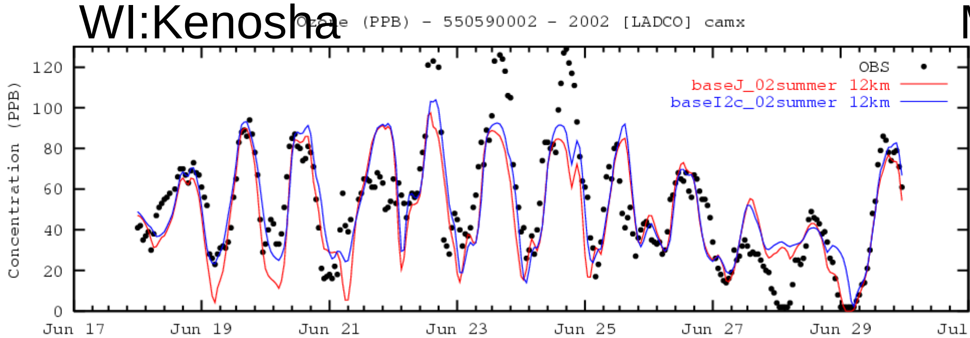
WI:Door



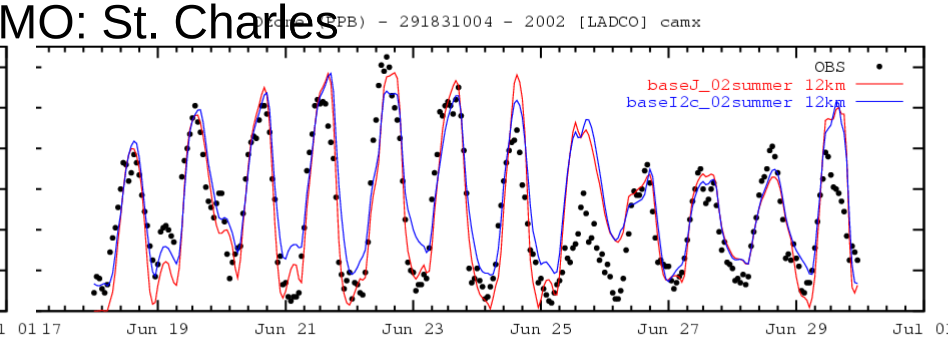
MO: STL County



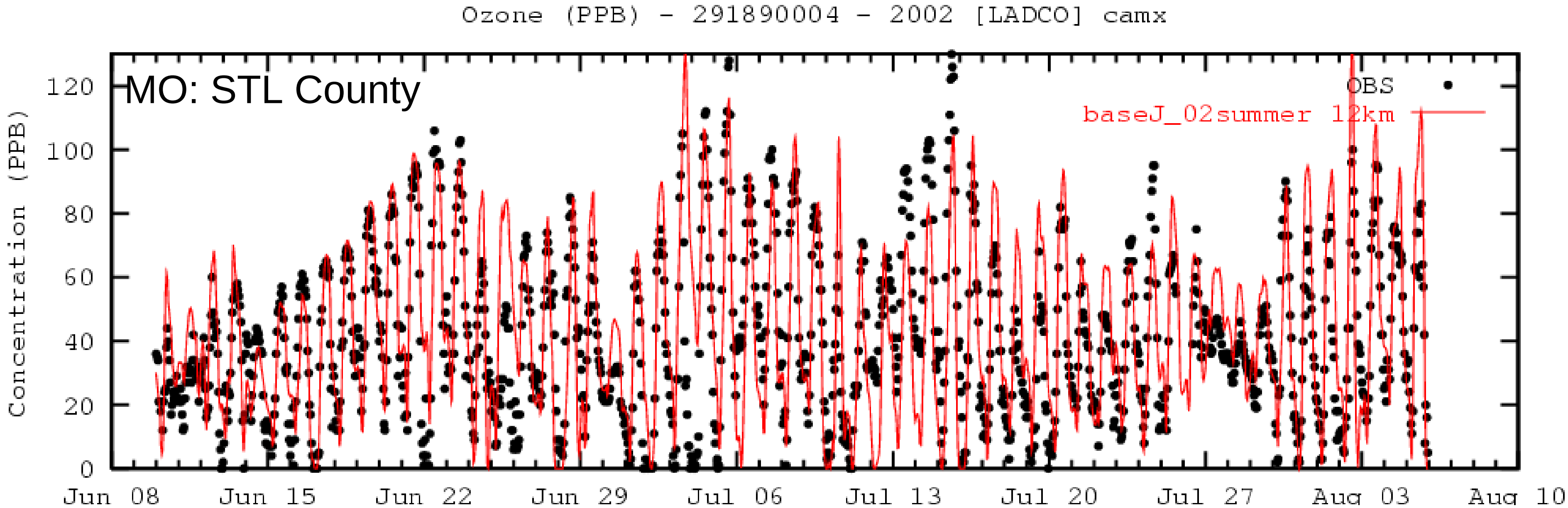
WI:Kenosha

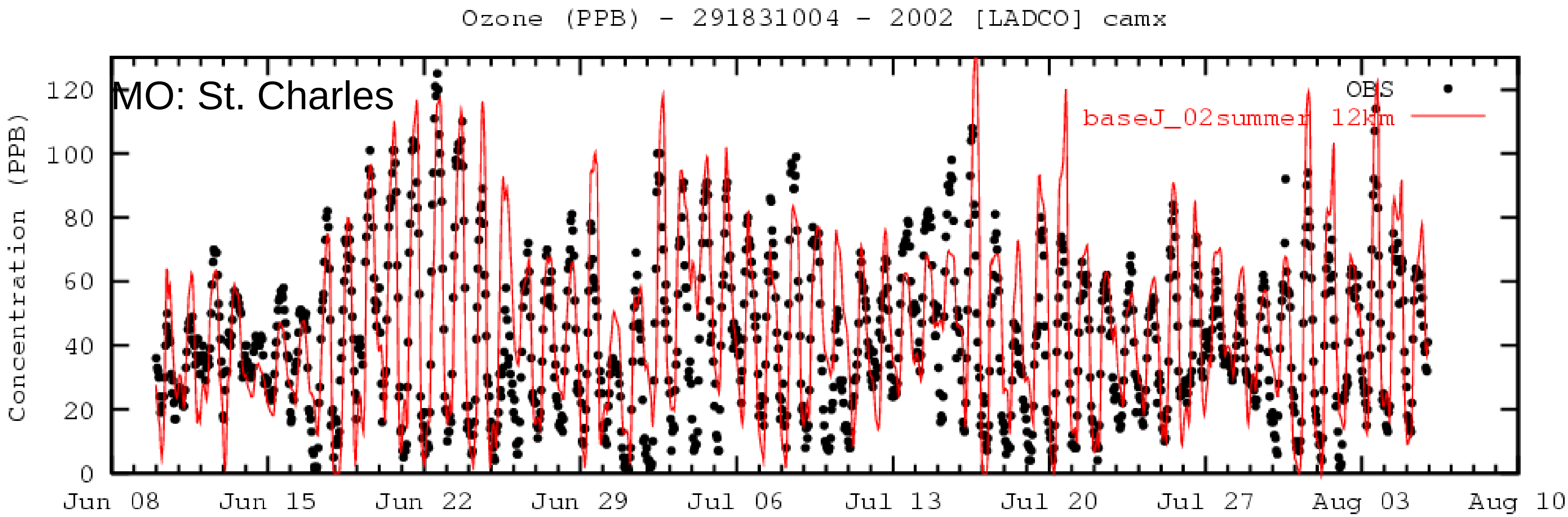


MO: St. Charles



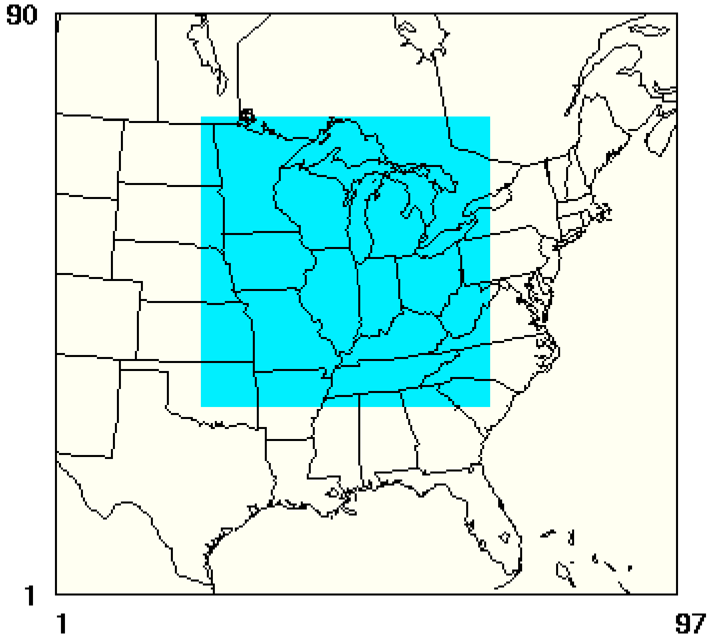
8-HRLY OZONE TIMESERIES PLOTS FOR ST. LOUIS

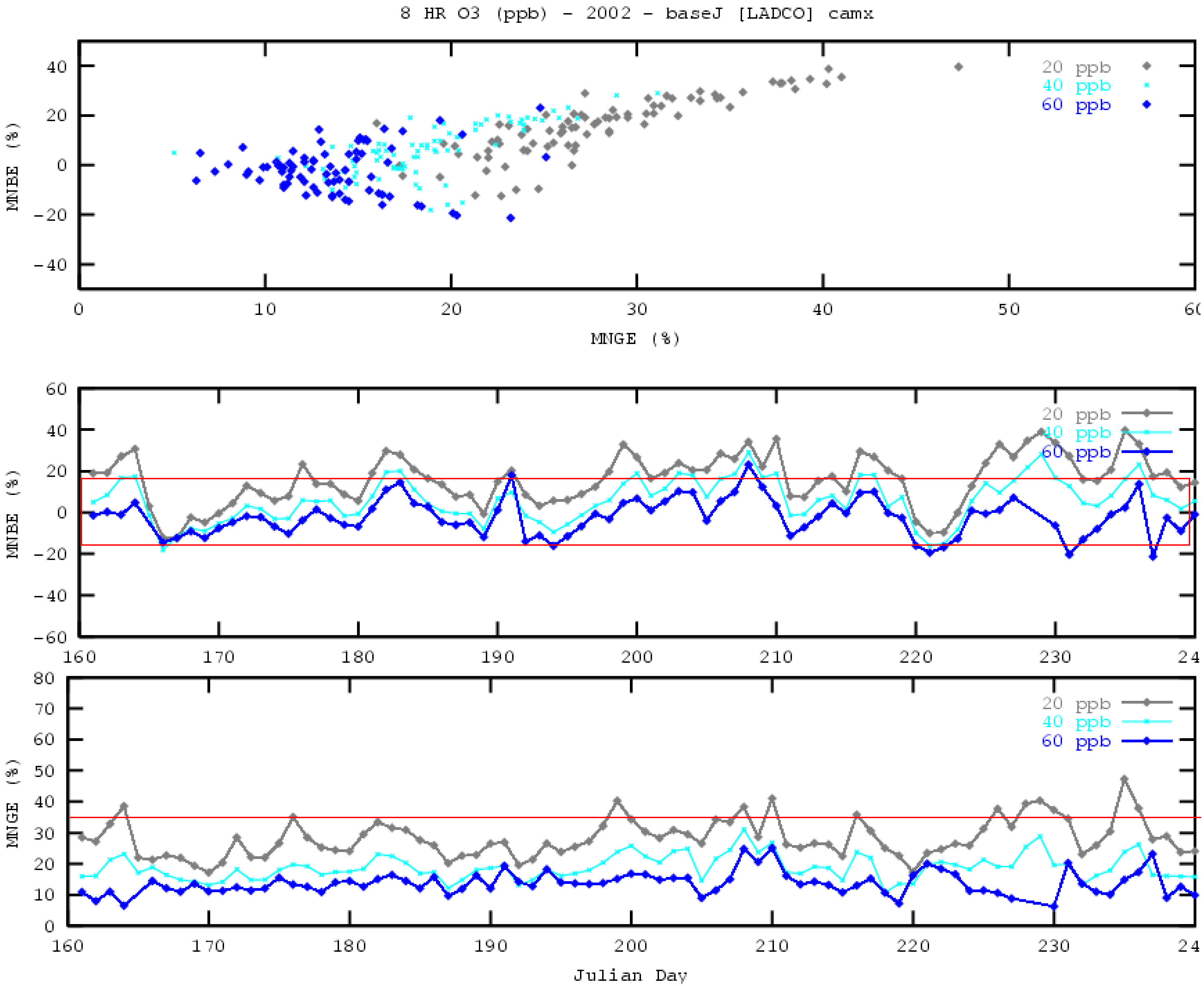




Metrics

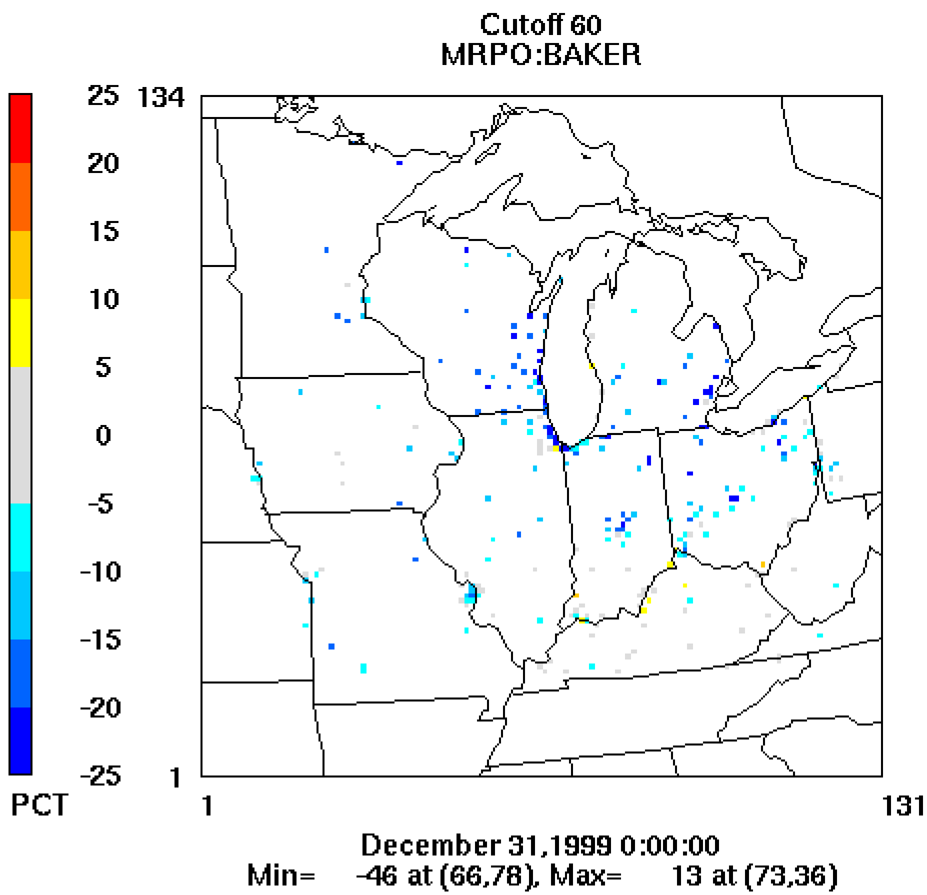
- **12 km – Base J**
- Summer 2002
- Metrics: MNBE, MNGE, mean OBS, mean PRED
- Minimum thresholds for metrics: 20, 40, and 60 ppb
  - Entire domain and entire summer
  - Entire domain and episode day
  - Entire summer and monitor location



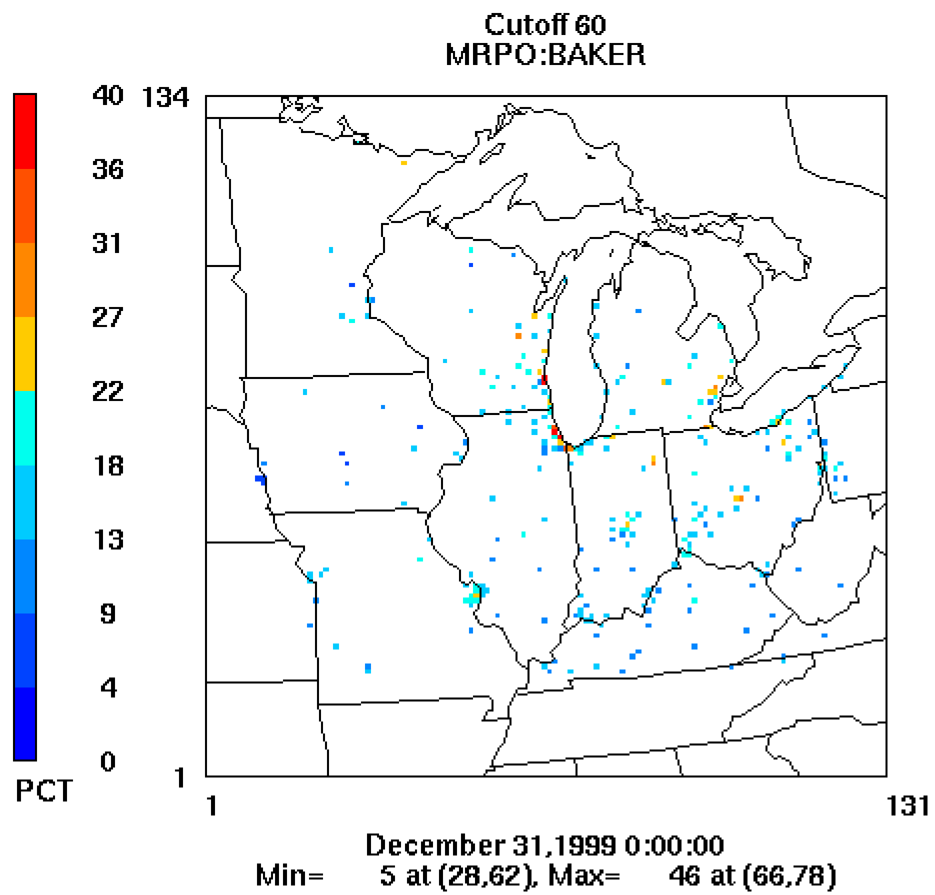

8 HR O3 (ppb) - 2002 - baseJ [LADCO] camx
MNBE (%)
MNGE (%)
20 ppb
40 ppb
60 ppb
MNBE (%)
MNGE (%)
Julian Day

Entire 2002 Summer Metrics by Location Averaged over Entire Summer using different minimum thresholds (20 and 60 ppb)

BIAS ERROR

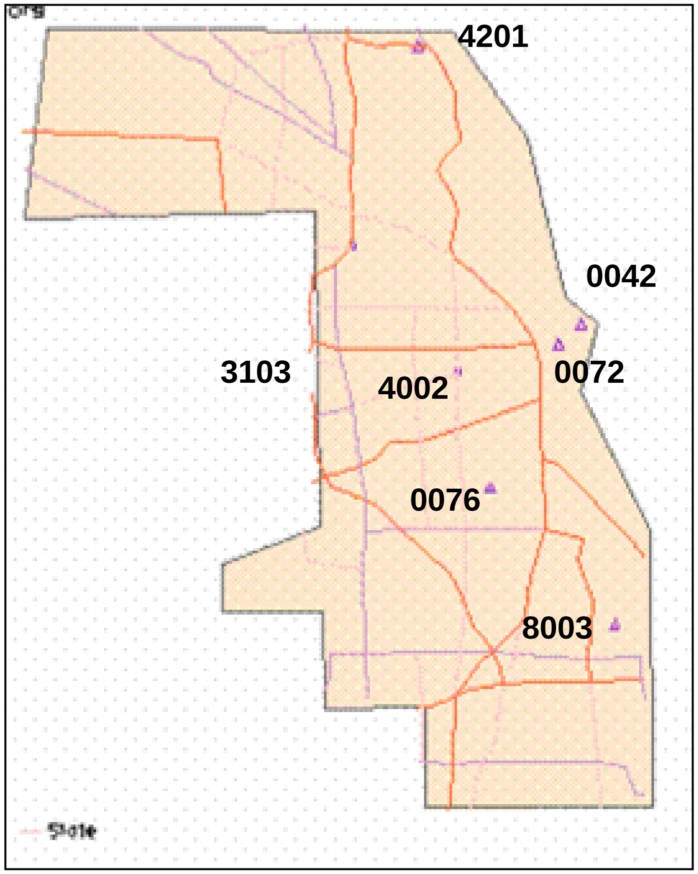


GROSS ERROR

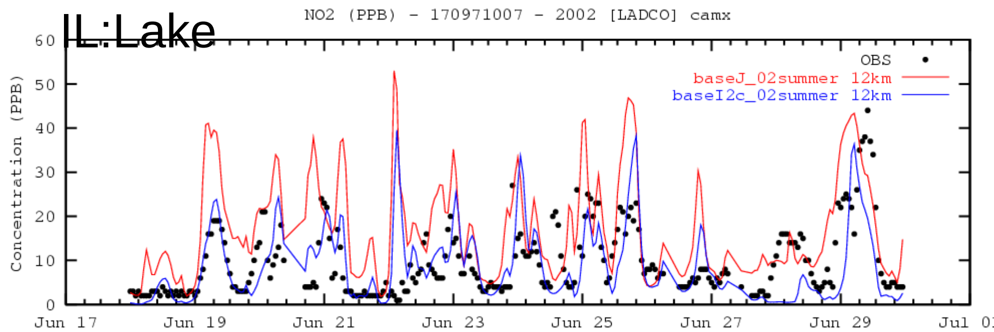


Time Series Plots

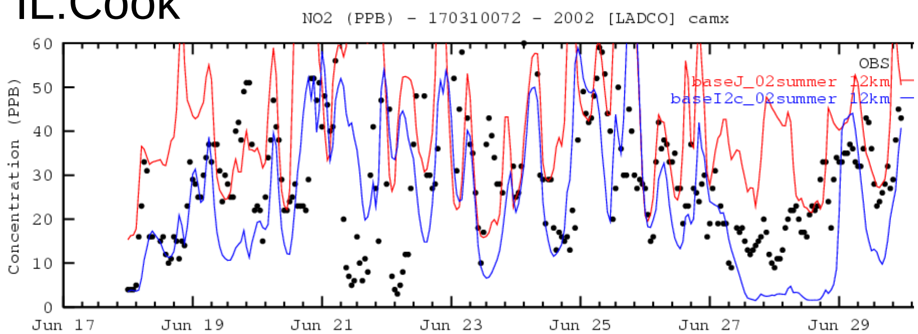
- HOURLY **NO2**
- Time-series plots at select monitors
- Monitors selected from areas that failed the attainment test after R2S2 scenario
- Base J and Base I shown on the plot



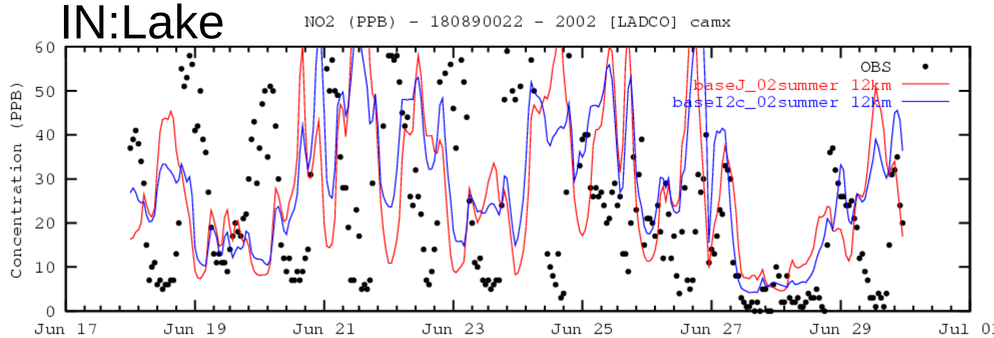
IL:Lake



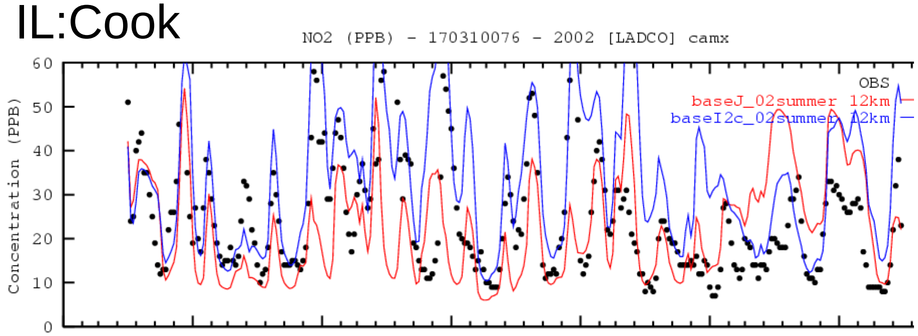
IL:Cook



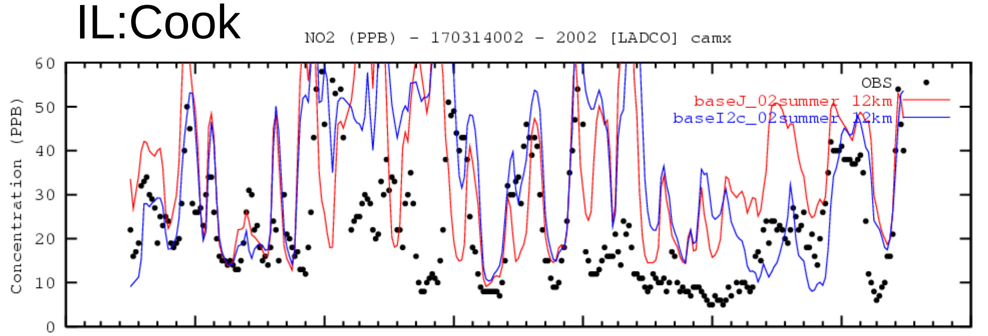
IN:Lake



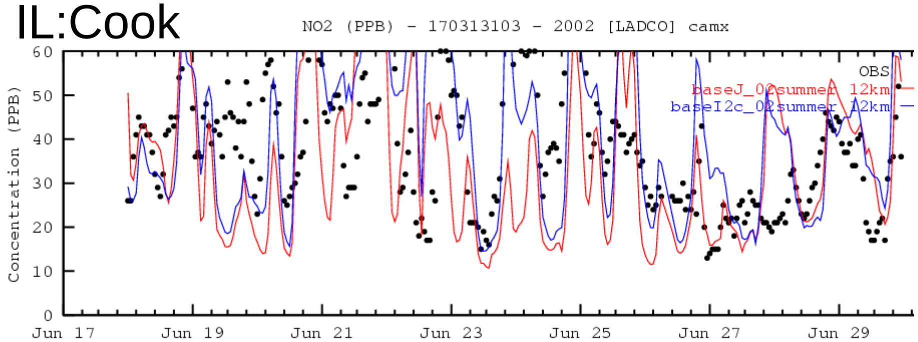
IL:Cook



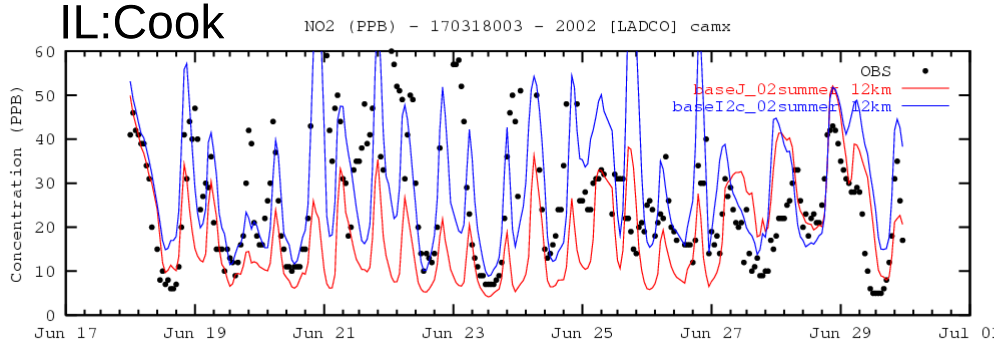
IL:Cook



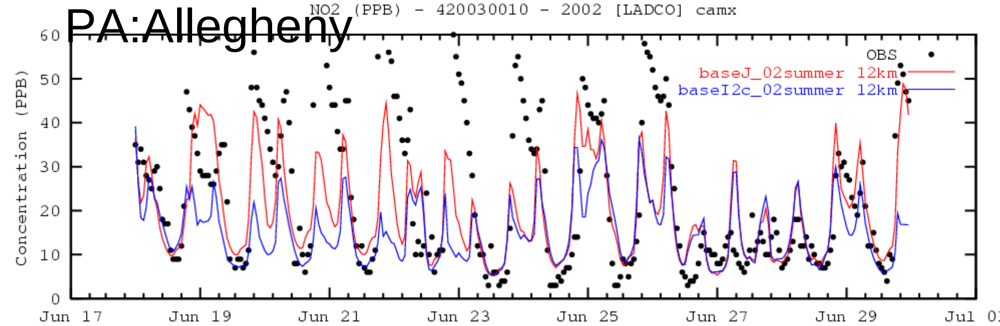
IL:Cook



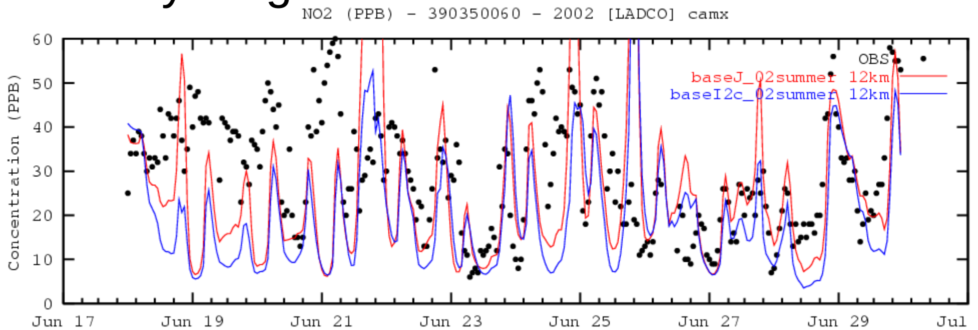
IL:Cook



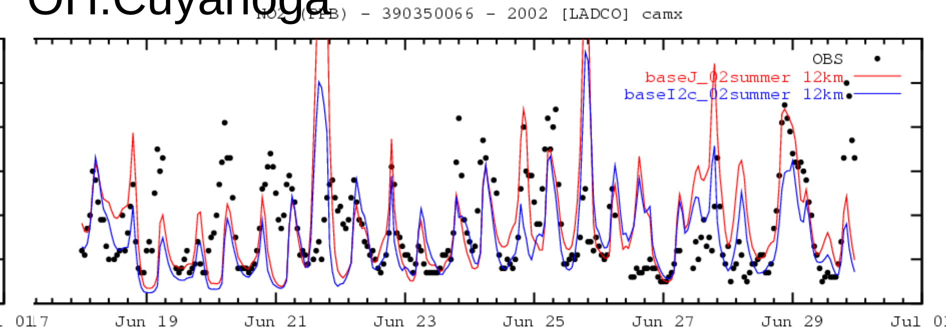
PA:Allegheny



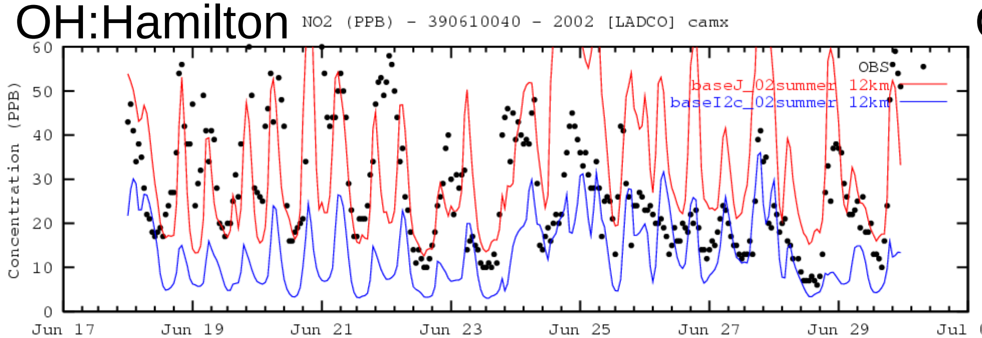
OH:Cuyahoga



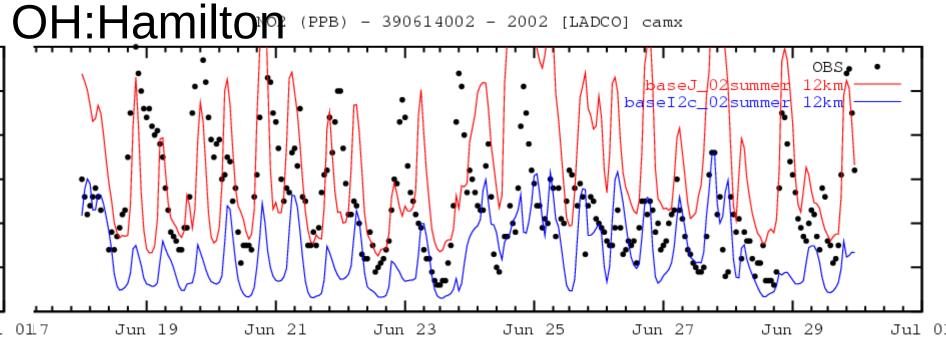
OH:Cuyahoga



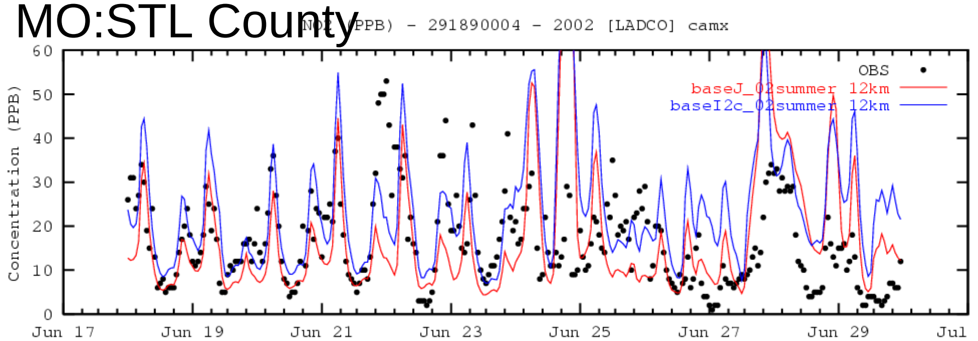
OH:Hamilton



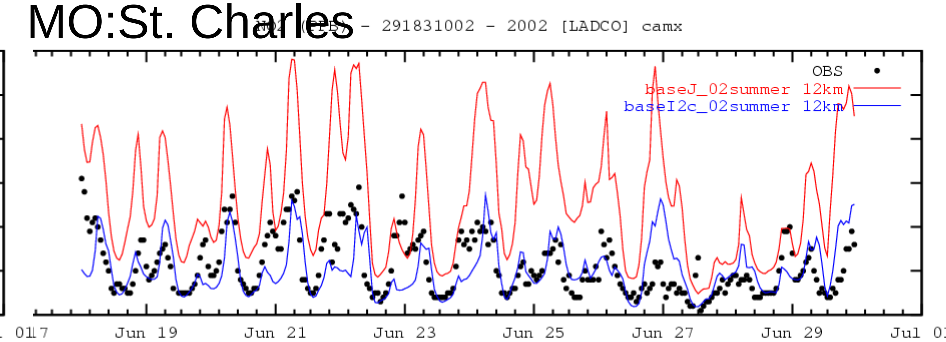
OH:Hamilton



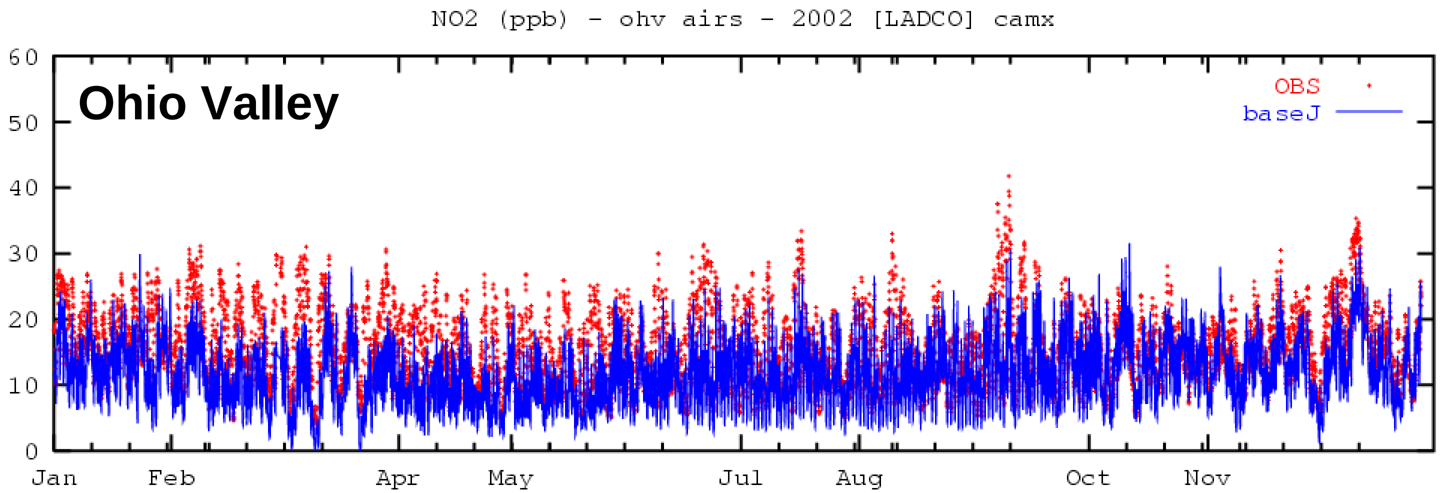
MO:STL County

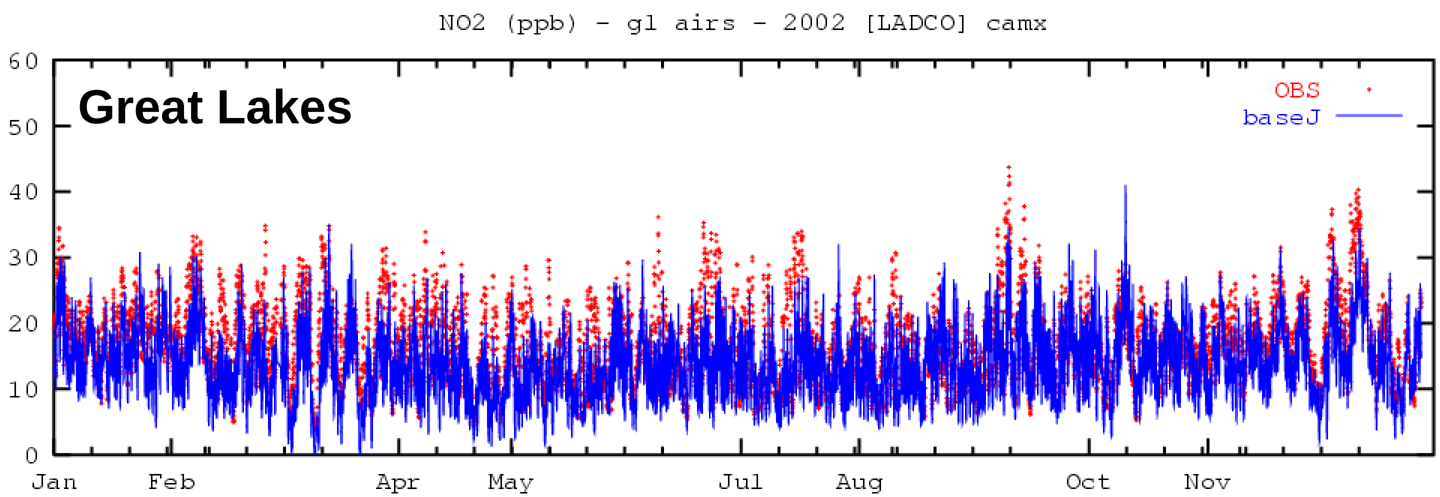


MO:St. Charles



Spatial Average Time Series: NOX

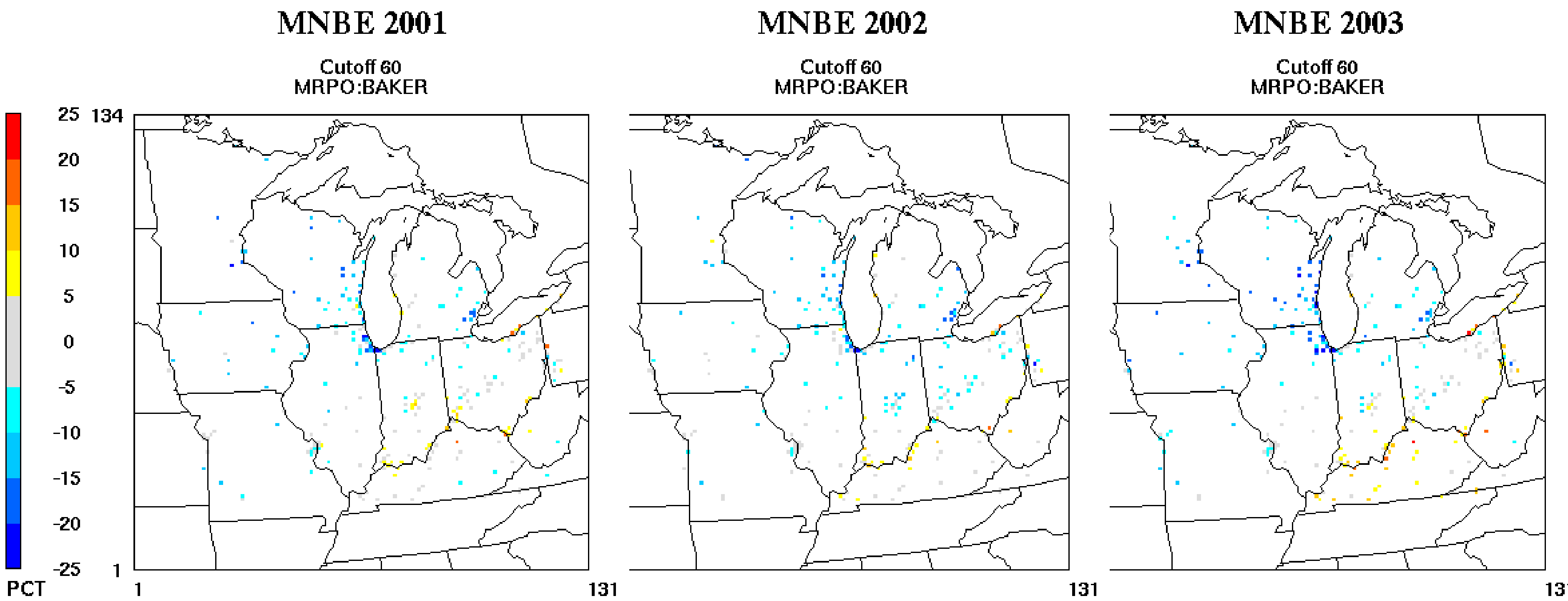




Metrics by Site Averaged over Summer Period

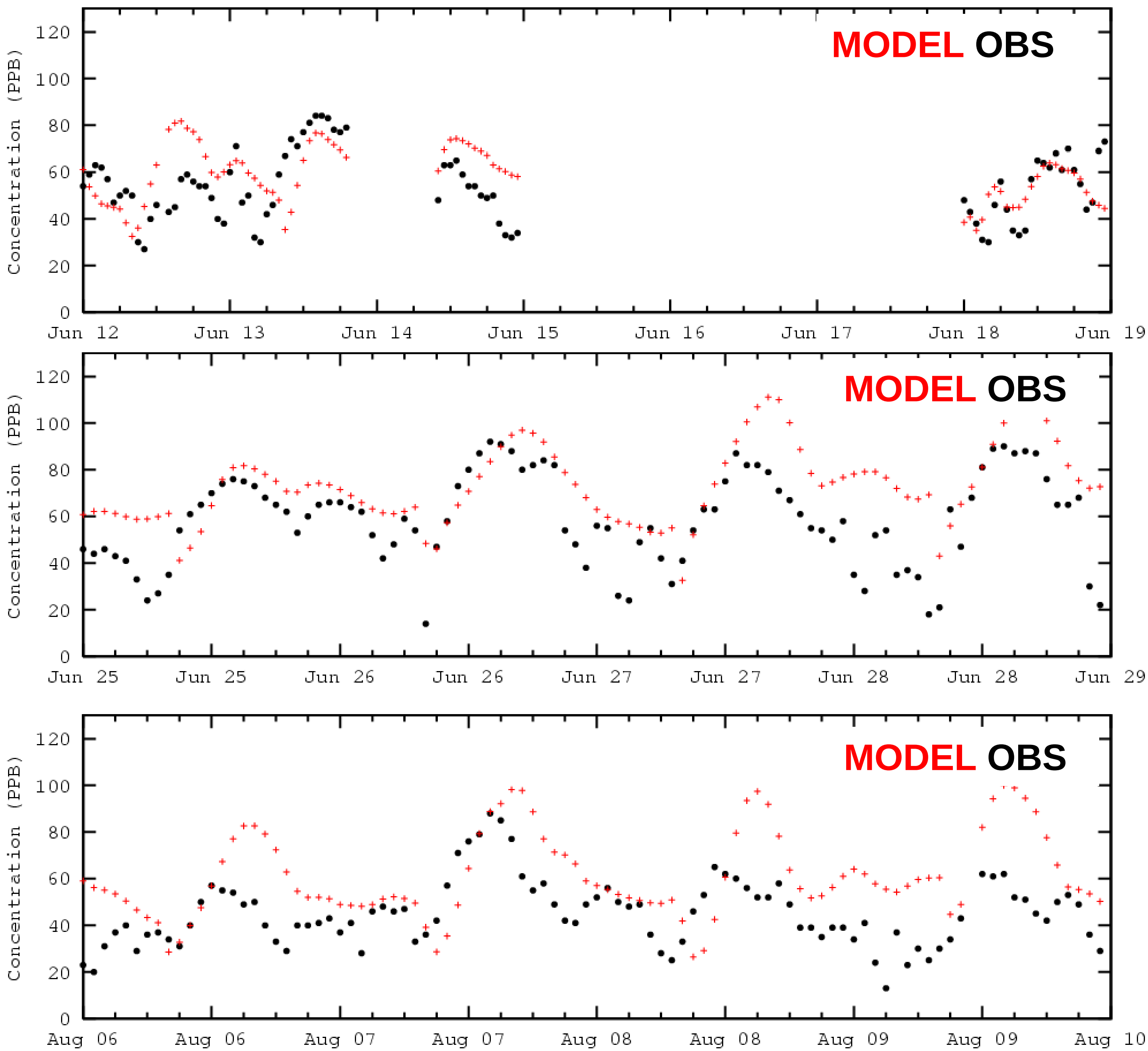
MNBE = mean normalized bias error

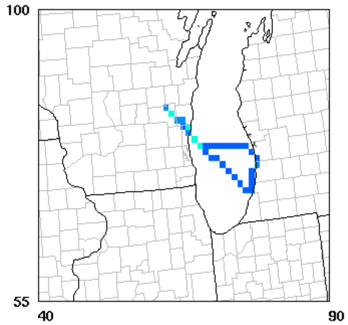
MNGE = mean normalized gross error



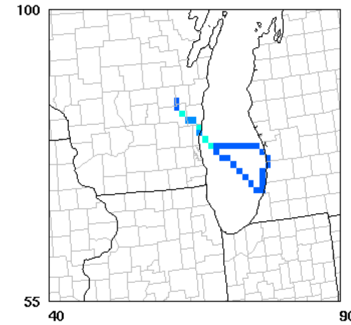
60 ppb metric cutoff

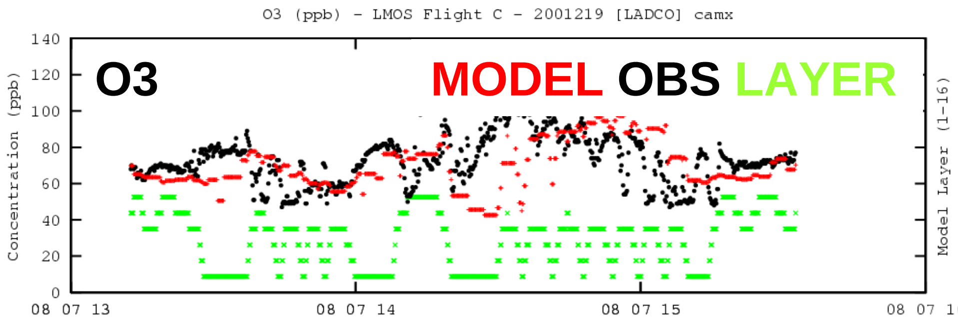
Ozone (PPB) - 170310042 - 2001 [LADCO] camx

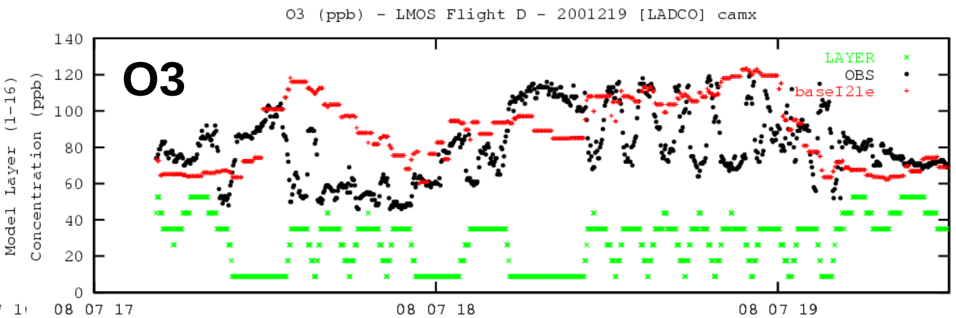


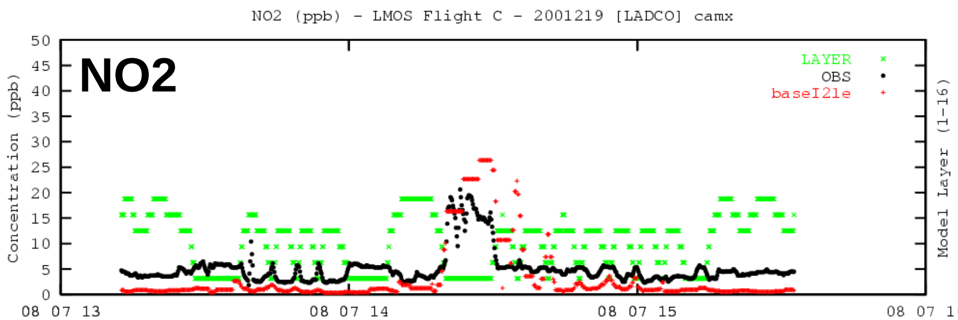


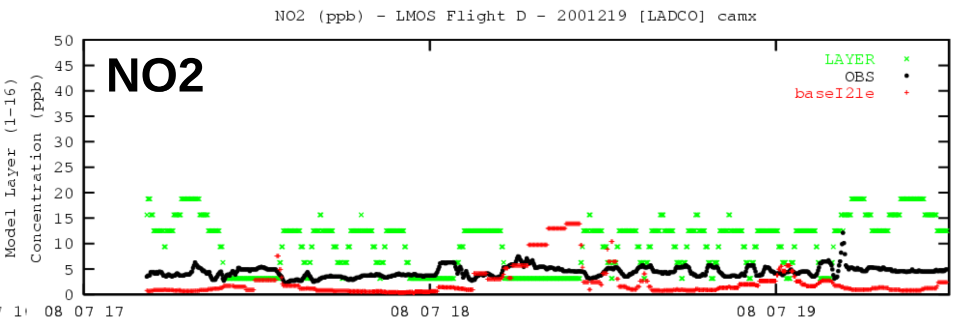
**Plots show flight paths and number of prediction-observation pairs in each grid cell*

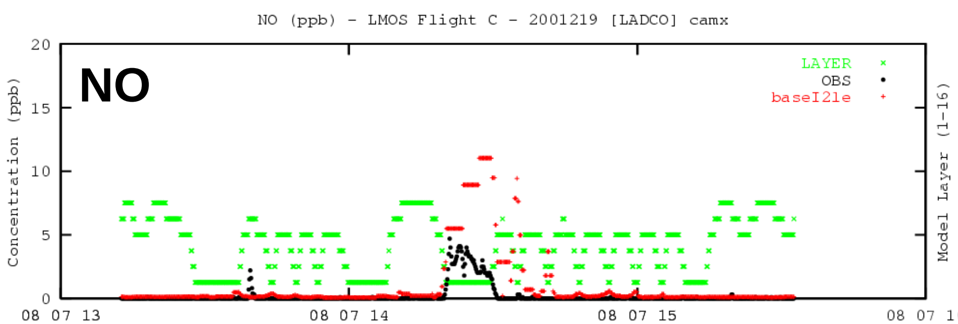


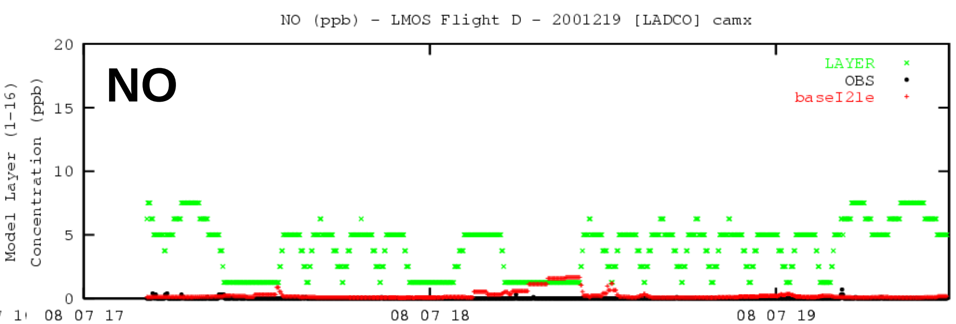






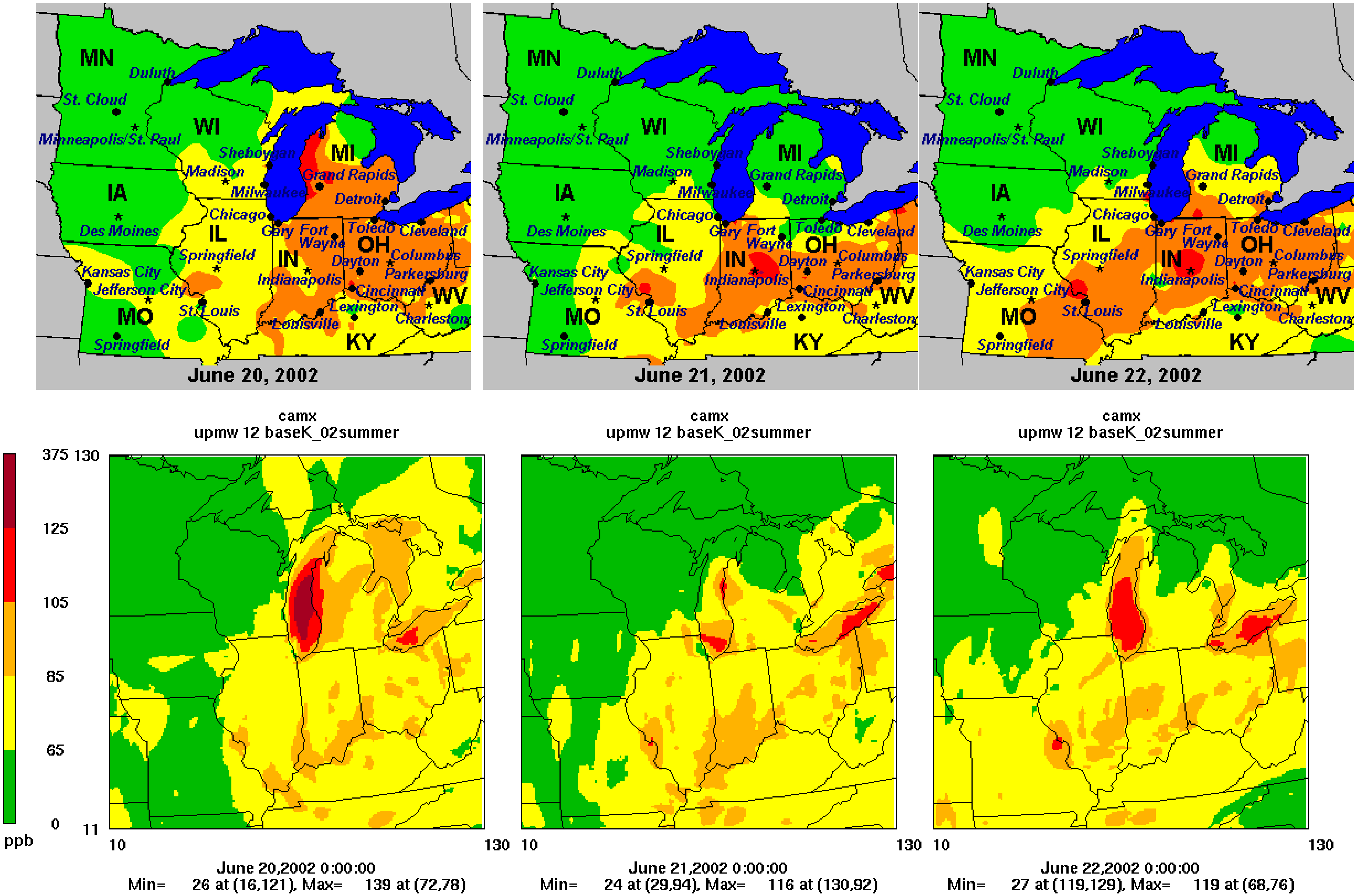


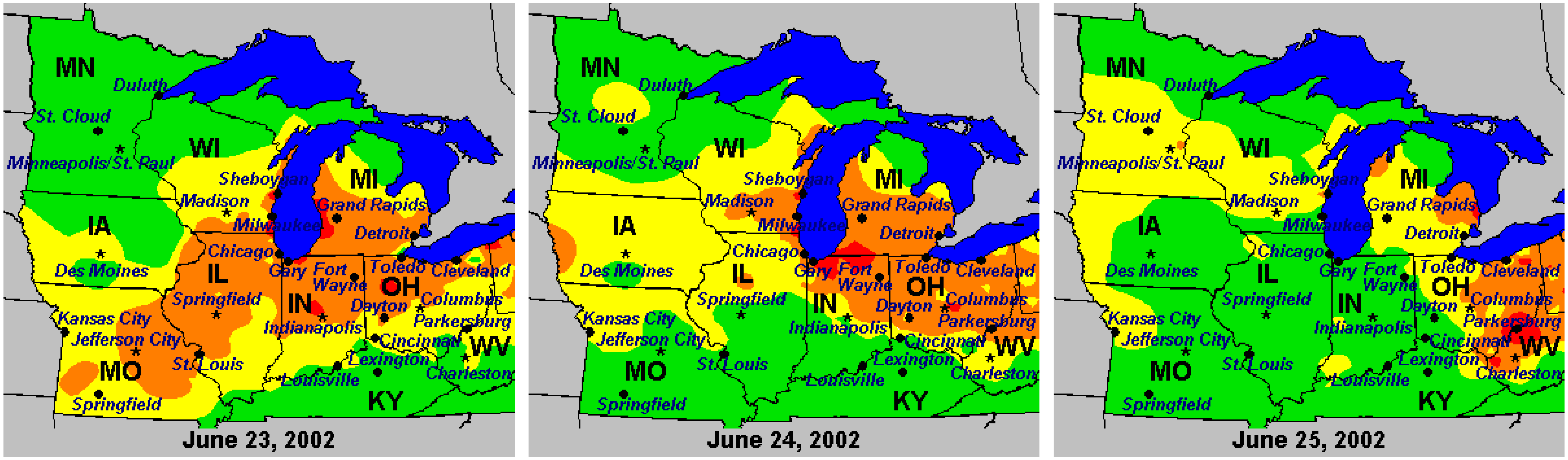




Base K (2002) Model Performance

Kirk Baker
LADCO/MRPO
April 2006

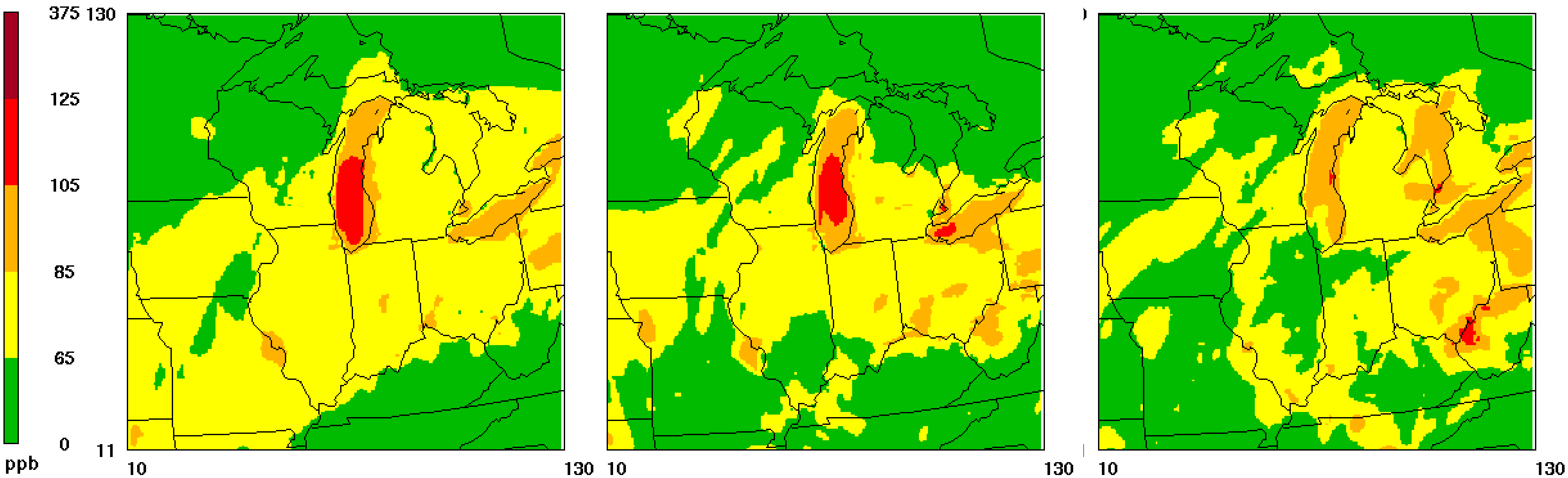

MN
WI
MI
IA
IL
IN
OH
MO
KY
WV
Duluth
St. Cloud
Minneapolis/St. Paul
Sheboygan
Madison
Milwaukee
Grand Rapids
Detroit
Chicago
Des Moines
Gary
Fort Wayne
Toledo
Cleveland
Springfield
Dayton
Columbus
Kansas City
Jefferson City
Indianapolis
Parkersburg
Cincinnati
St. Louis
Lexington
Louisville
Charleston
June 20, 2002
June 21, 2002
June 22, 2002
camx
upmw 12 baseK_02summer
ppb
375
125
105
85
65
0
130
11
10
130
June 20,2002 0:00:00
Min= 26 at (16,121), Max= 139 at (72,78)
June 21,2002 0:00:00
Min= 24 at (29,94), Max= 116 at (130,92)
June 22,2002 0:00:00
Min= 27 at (119,129), Max= 119 at (68,76)



camx
upmw 12 baseK_02summer

camx
upmw 12 baseK_02summer

camx
upmw 12 baseK_02summer



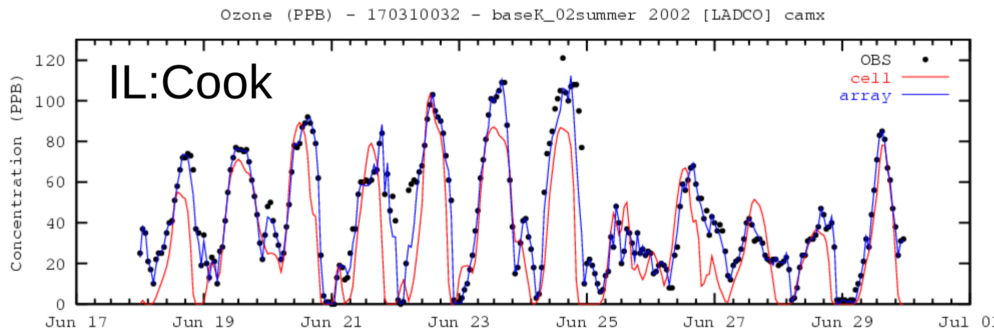
June 23,2002 0:00:00
Min= 31 at (99,11), Max= 120 at (70,82)

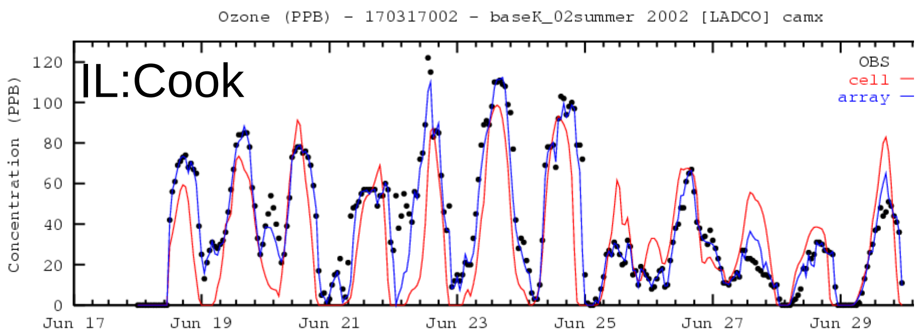
June 24,2002 0:00:00
Min= 20 at (124,93), Max= 113 at (103,77)

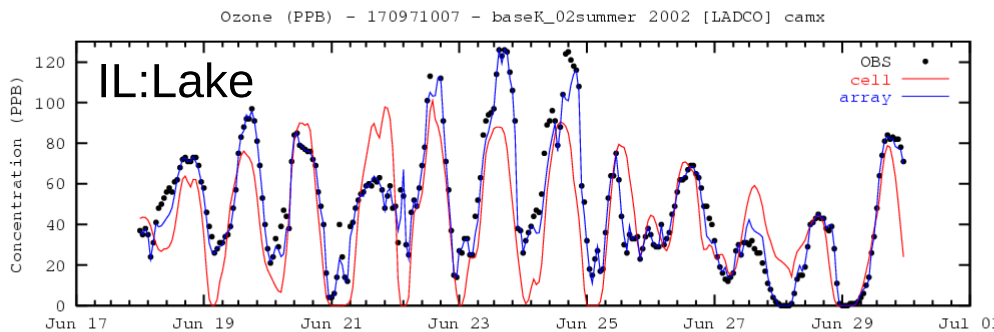
June 25,2002 0:00:00
Min= 14 at (70,66), Max= 119 at (112,43)

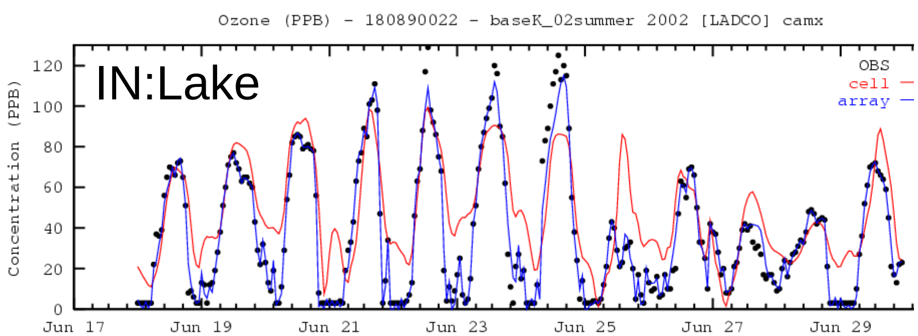
Chicago and Gary

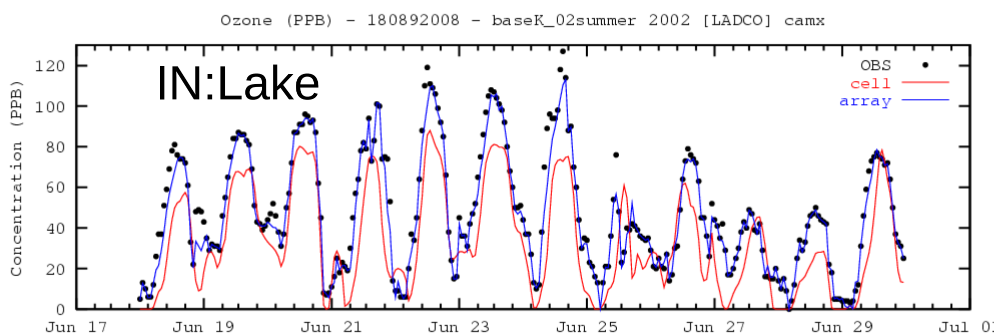
- Times series show predictions in monitor location cell (cell) and 3x3 array best match (array)



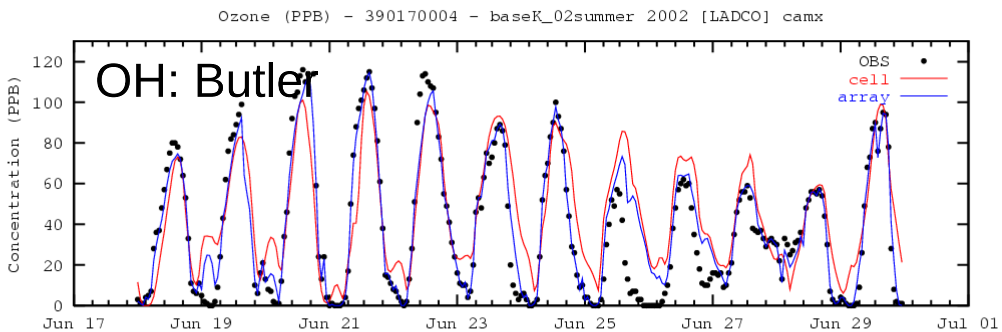


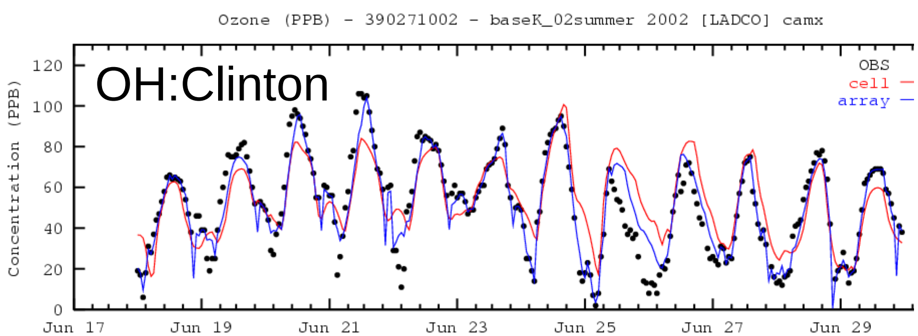


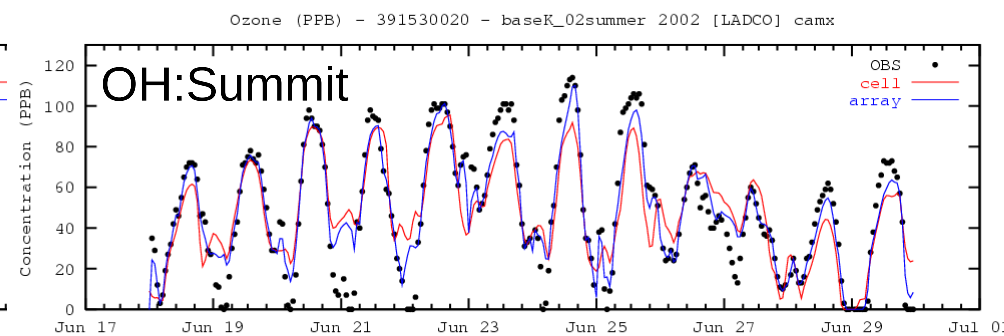


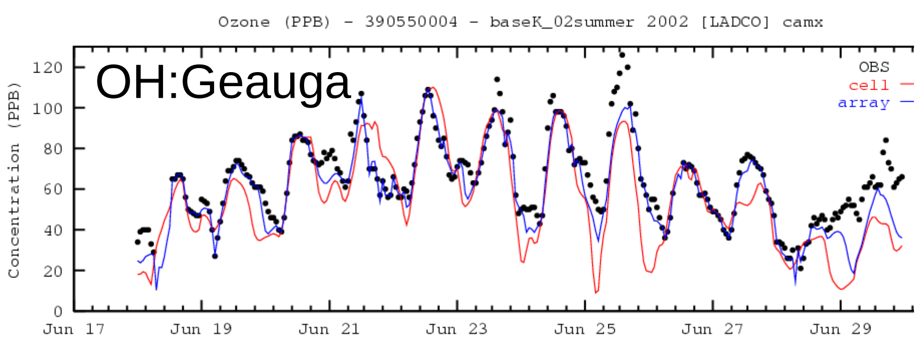


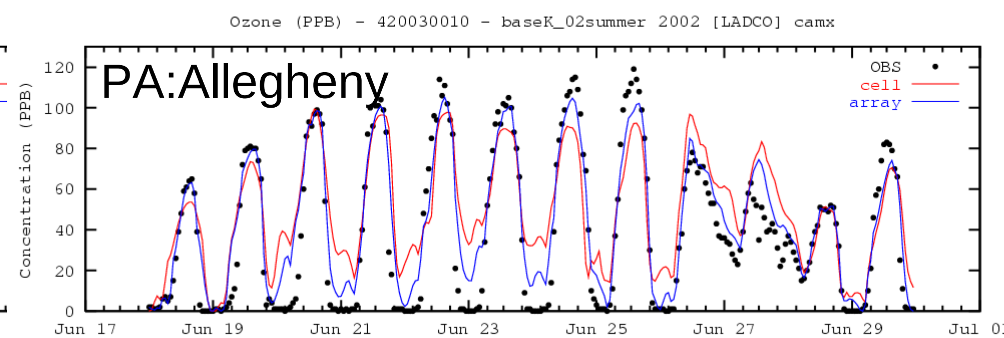
Ohio & Pennsylvania





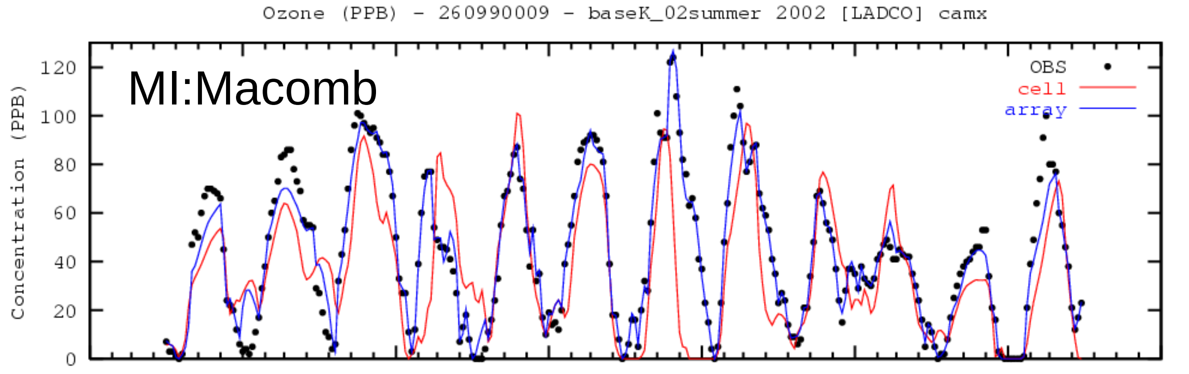


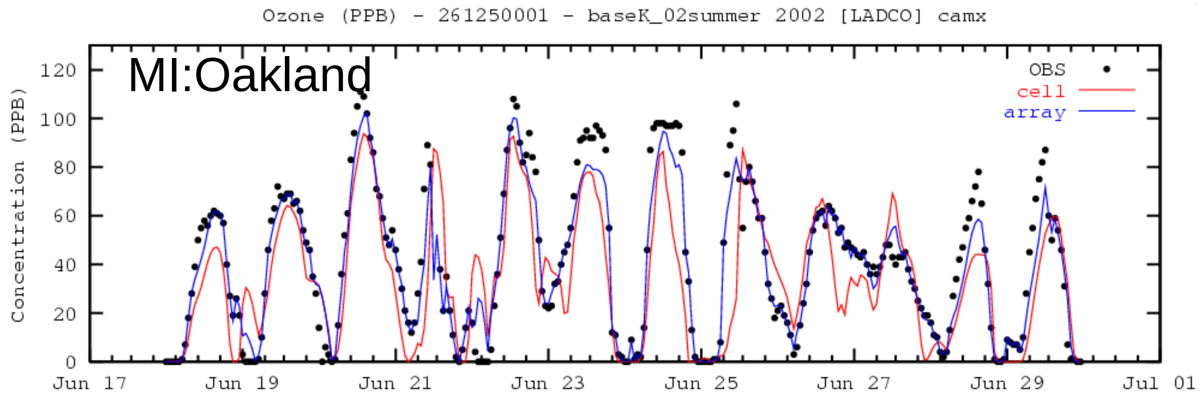


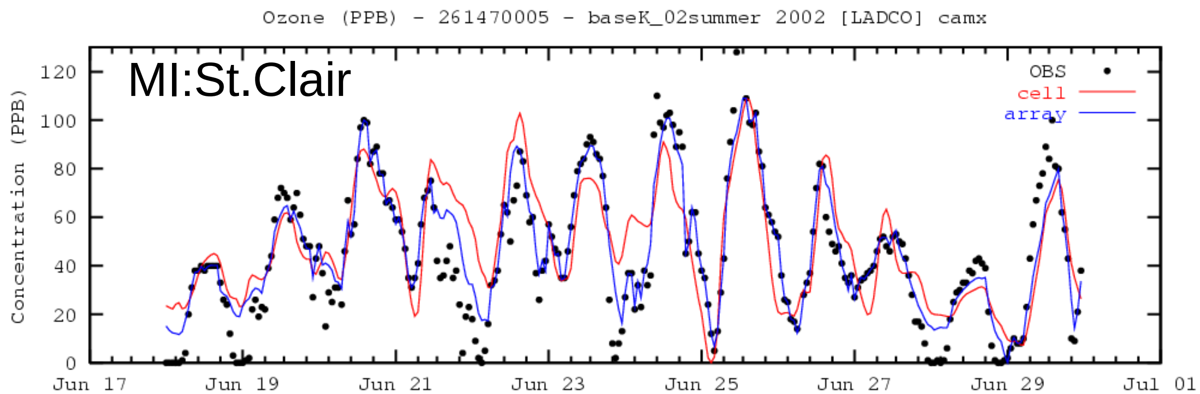


ELECTRONIC FILING, RECEIVED, CLERK'S OFFICE, JANUARY 5, 2007
* * * * * PC #10 * * * * *

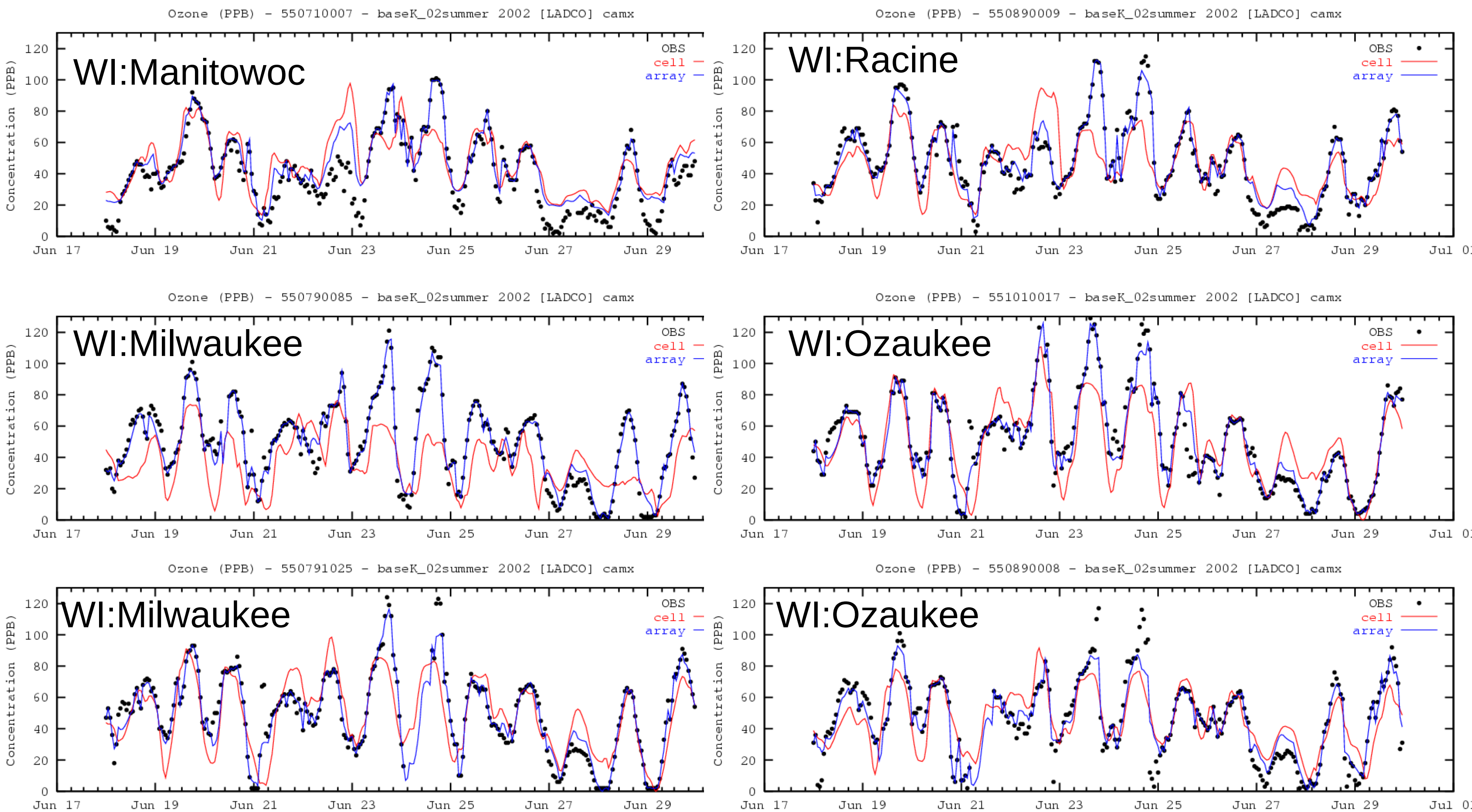
Detroit



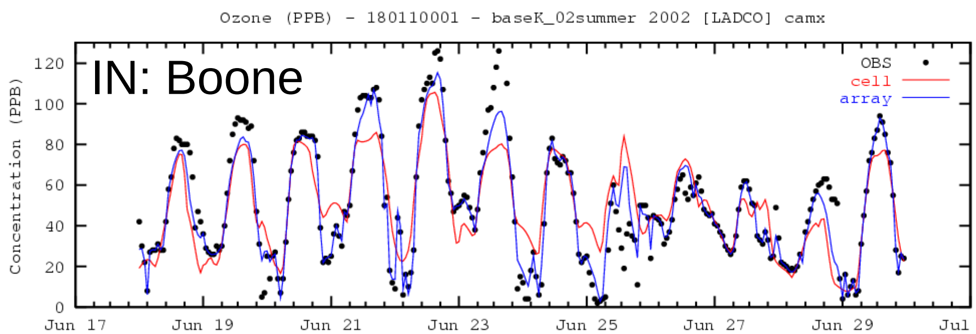


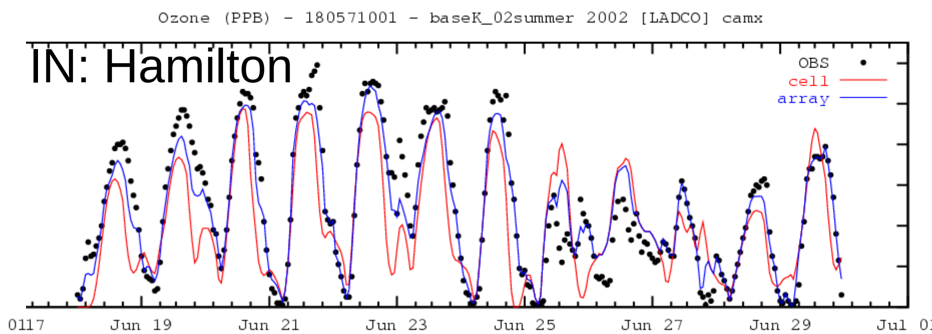


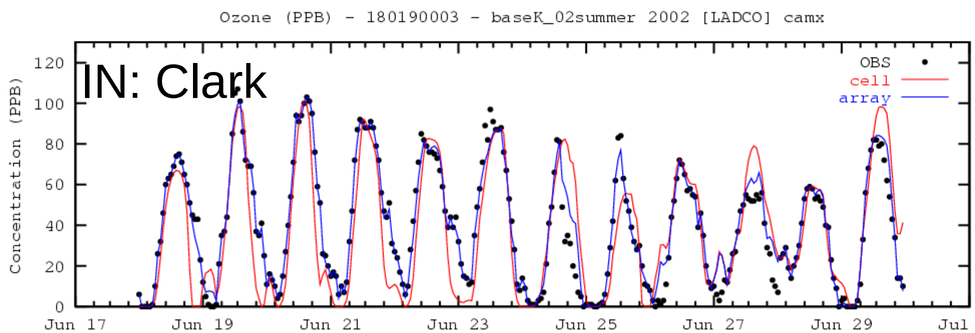
Wisconsin

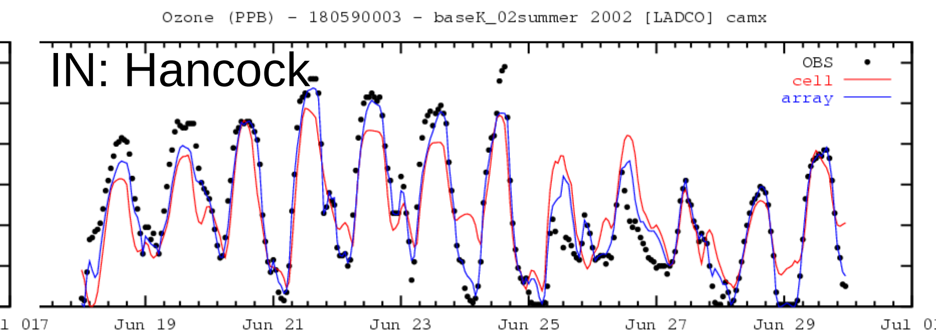

Ozone (PPB) - 550710007 - baseK_02summer 2002 [LADCO] camx
WI:Manitowoc
Ozone (PPB) - 550890009 - baseK_02summer 2002 [LADCO] camx
WI:Racine
Ozone (PPB) - 550790085 - baseK_02summer 2002 [LADCO] camx
WI:Milwaukee
Ozone (PPB) - 551010017 - baseK_02summer 2002 [LADCO] camx
WI:Ozaukee
Ozone (PPB) - 550791025 - baseK_02summer 2002 [LADCO] camx
WI:Milwaukee
Ozone (PPB) - 550890008 - baseK_02summer 2002 [LADCO] camx
WI:Ozaukee
OBS
cell
array
Concentration (PPB)
0
20
40
60
80
100
120
Jun 17
Jun 19
Jun 21
Jun 23
Jun 25
Jun 27
Jun 29
Jul 01

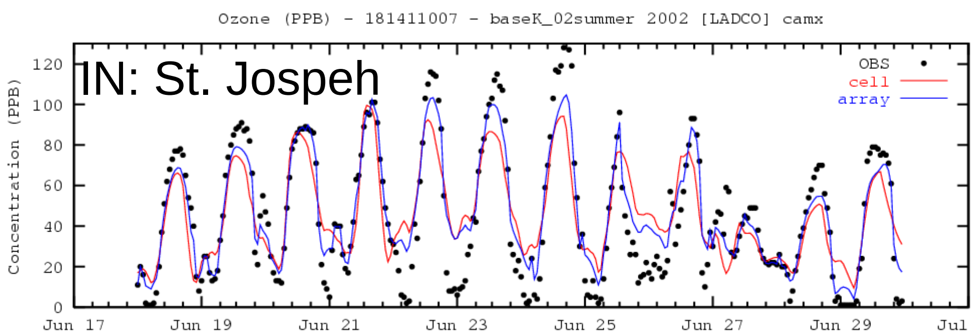
Indiana

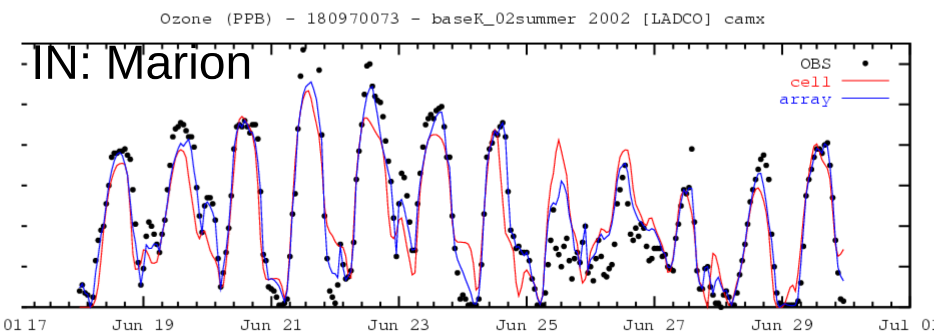

Ozone (PPB) - 180110001 - baseK_02summer 2002 [LADCO] camx
IN: Boone
OBS
cell
array
Concentration (PPB)
0
20
40
60
80
100
120
Jun 17
Jun 19
Jun 21
Jun 23
Jun 25
Jun 27
Jun 29
Jul 01


Ozone (PPB) - 180571001 - baseK_02summer 2002 [LADCO] camx
IN: Hamilton
OBS
cell
array
Jun 17
Jun 19
Jun 21
Jun 23
Jun 25
Jun 27
Jun 29
Jul 01

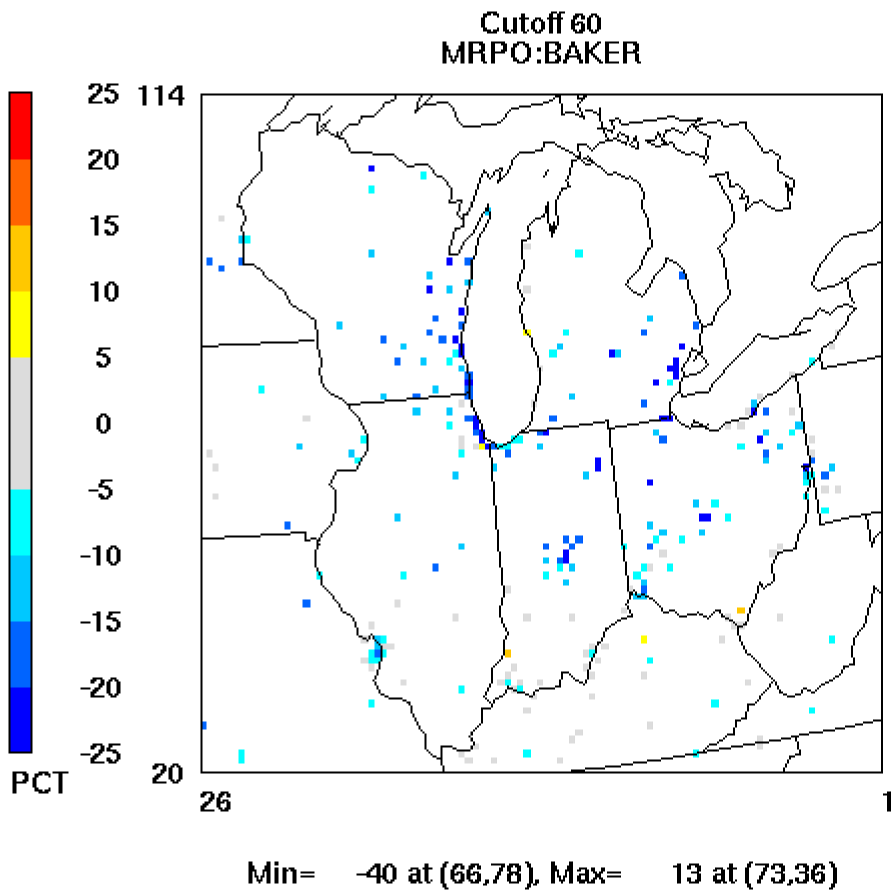

Ozone (PPB) - 180190003 - baseK_02summer 2002 [LADCO] camx
IN: Clark
OBS
cell
array
Concentration (PPB)
0
20
40
60
80
100
120
Jun 17
Jun 19
Jun 21
Jun 23
Jun 25
Jun 27
Jun 29
Jul 01


Ozone (PPB) - 180590003 - baseK_02summer 2002 [LADCO] camx
IN: Hancock
OBS
cell
array
Jun 17
Jun 19
Jun 21
Jun 23
Jun 25
Jun 27
Jun 29
Jul 01

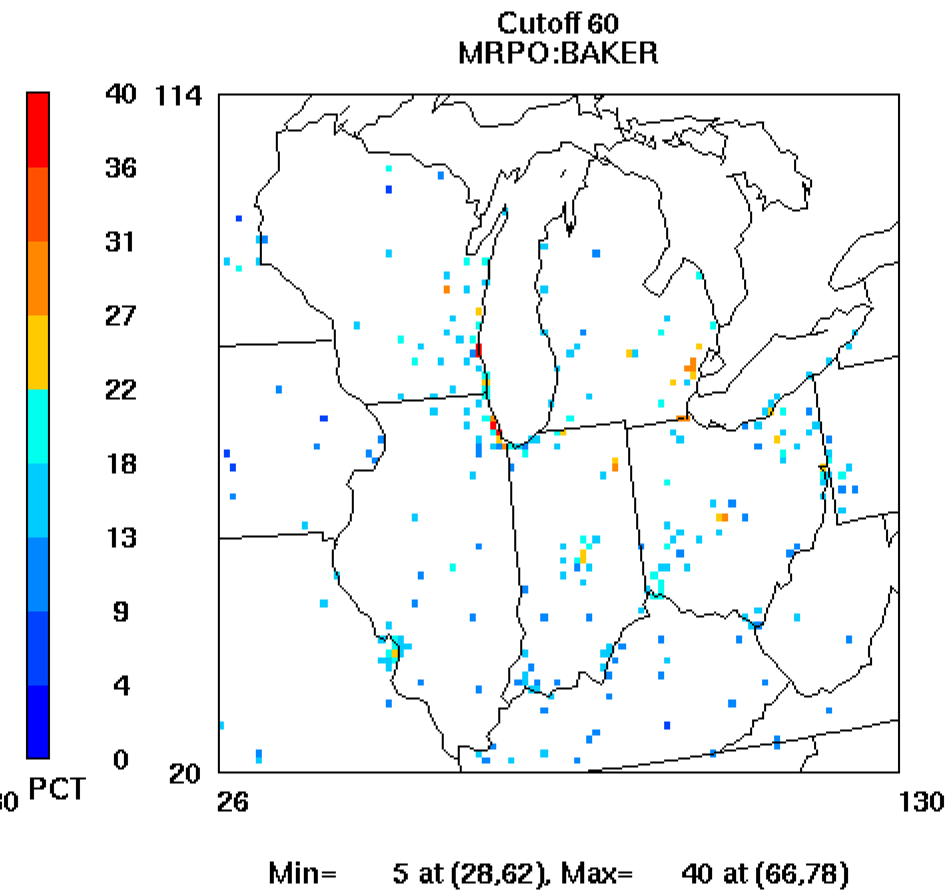

Ozone (PPB) - 181411007 - baseK_02summer 2002 [LADCO] camx
IN: St. Jospeh
OBS
cell
array
Concentration (PPB)
0
20
40
60
80
100
120
Jun 17
Jun 19
Jun 21
Jun 23
Jun 25
Jun 27
Jun 29
Jul 01


Ozone (PPB) - 180970073 - baseK_02summer 2002 [LADCO] camx
IN: Marion
OBS
cell
array
Jun 17
Jun 19
Jun 21
Jun 23
Jun 25
Jun 27
Jun 29
Jul 01

Mean Normalized Bias

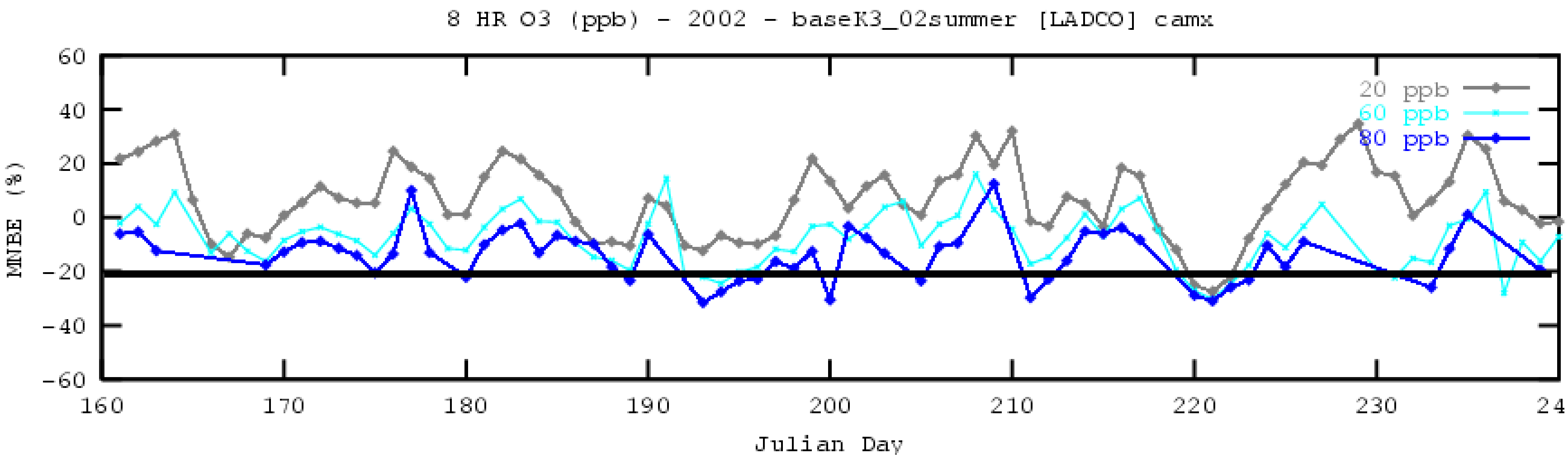


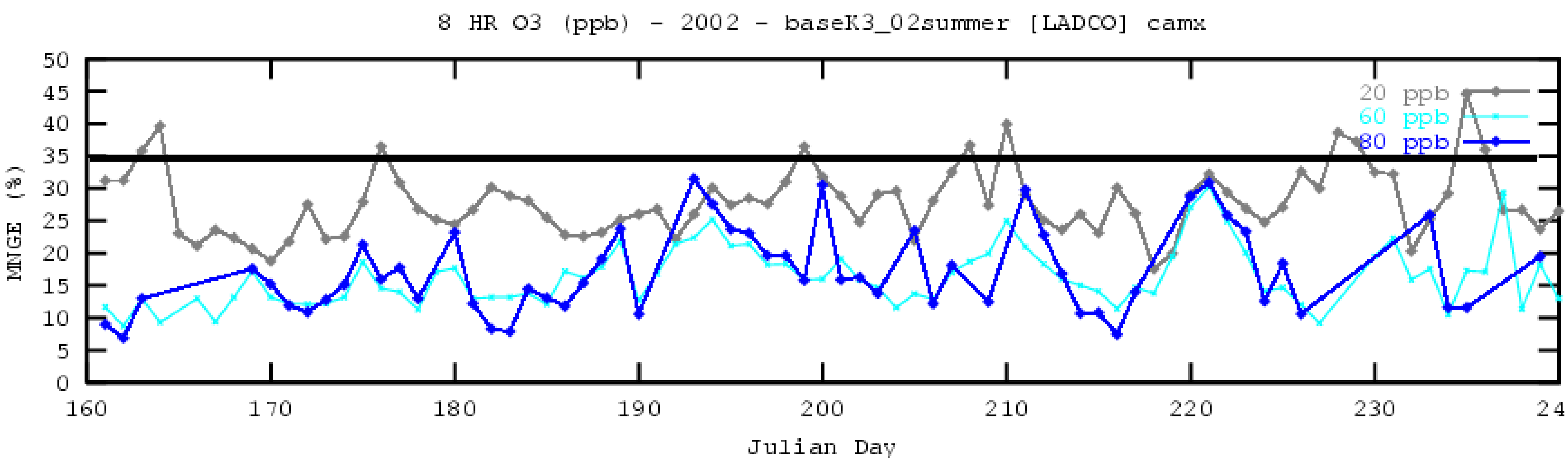
Mean Normalized Gross Error



Mean Bias (top) and Mean Gross Error (bottom)

over all sites by episode day





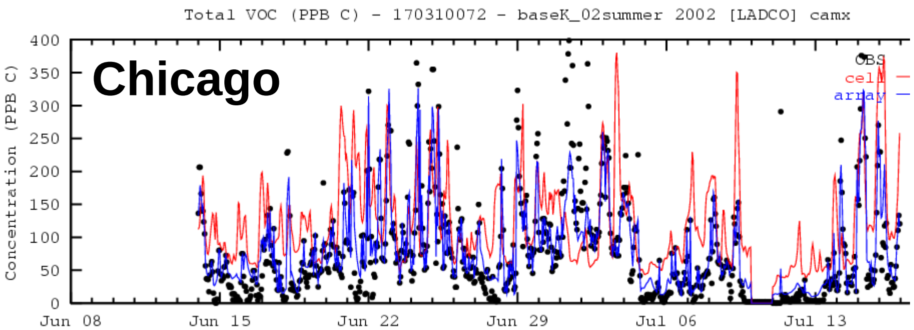
VOC and NOX Performance

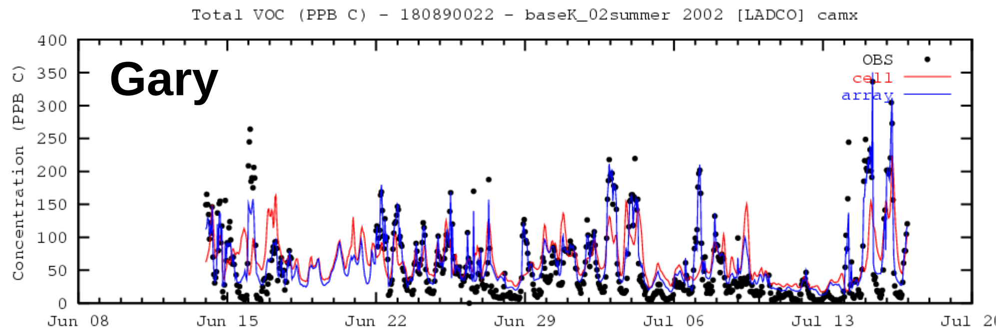
- Modeled Total VOC = PAR + OLE + OLE2 + TOL + XYL + ETH + FORM + ALD2 + ISOP
- Measured Total VOC = sum of all measured hydrocarbon species at the monitor

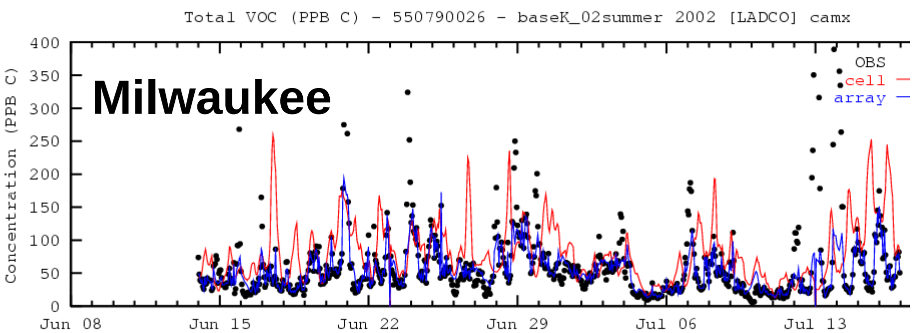
- Modeled NOX = NO + NO2 + NXOY + HONO + PNA
- No NOX measured at the Milwaukee site

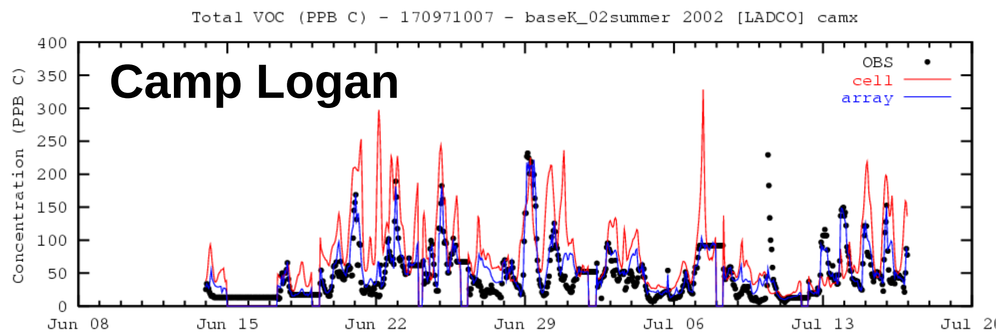
- All time-series plots show 2 predictions: the cell containing the monitor and the best match in a 5x5 cell array around the cell containing the monitor

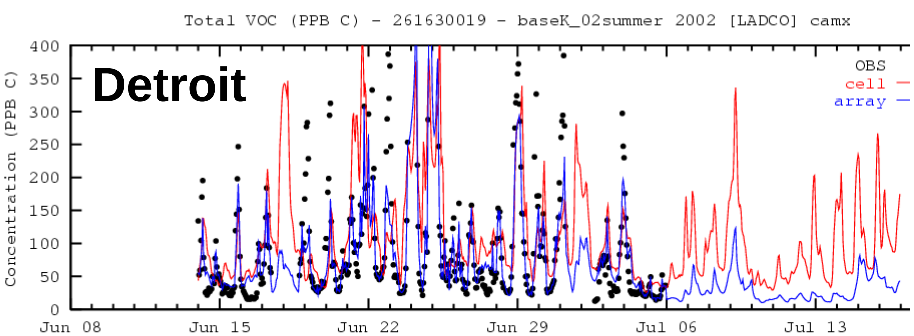
Total VOC (ppb c)

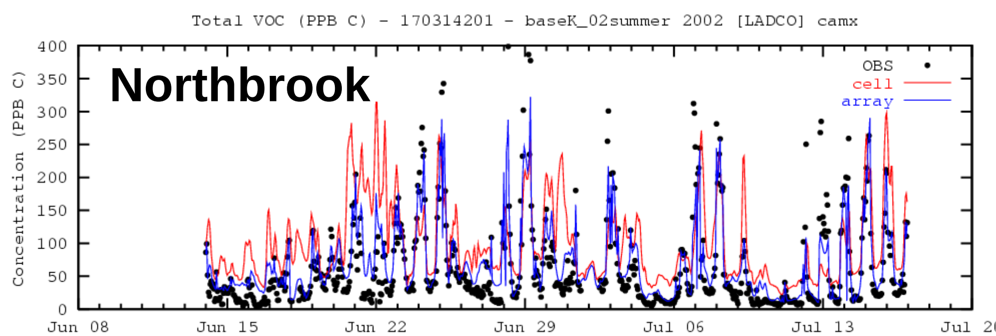




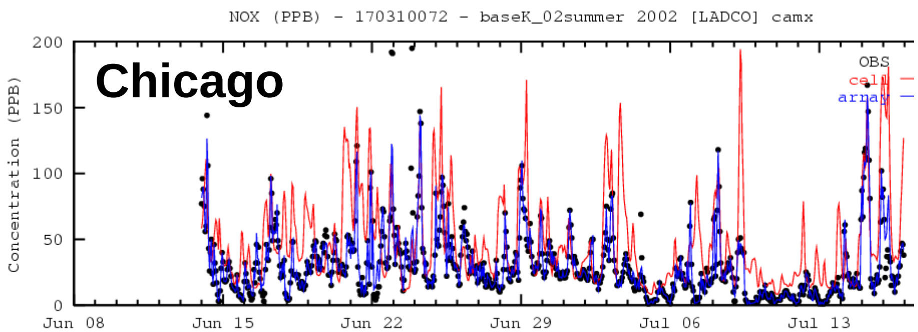


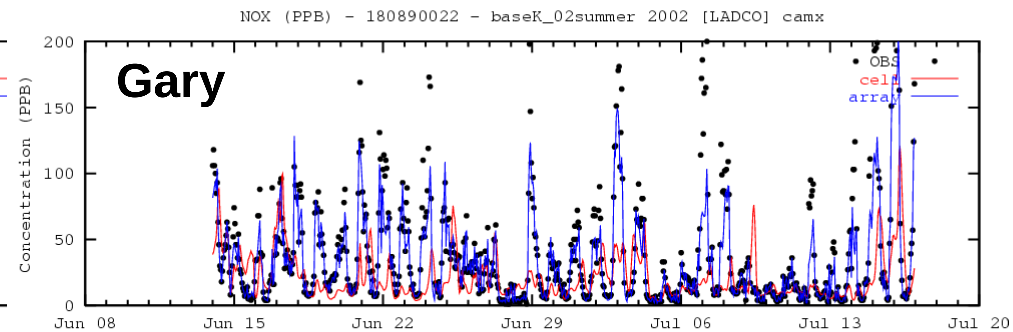






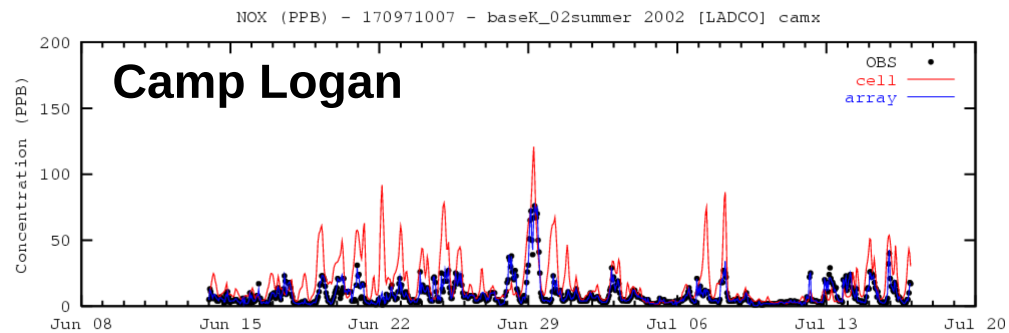
NOx (ppb)

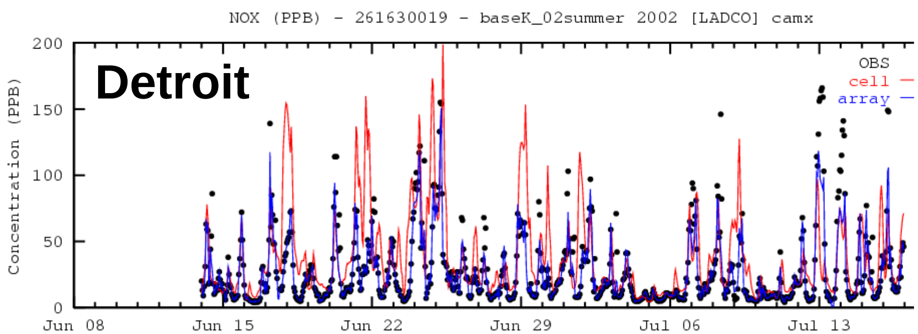


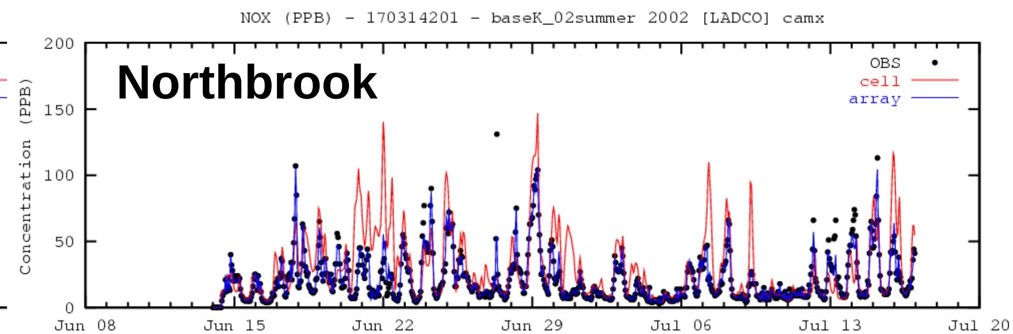


Milwaukee

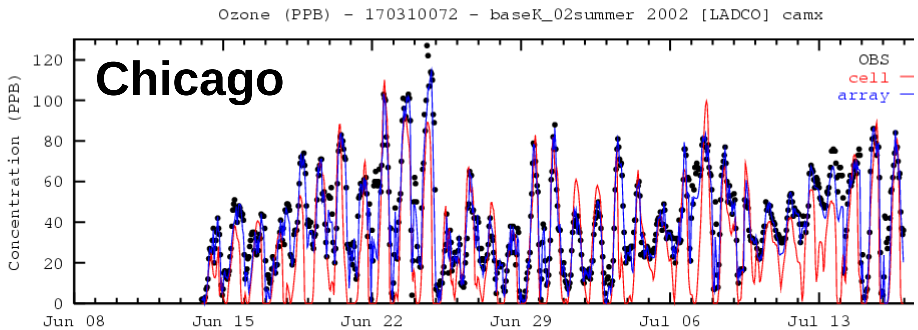
N/A

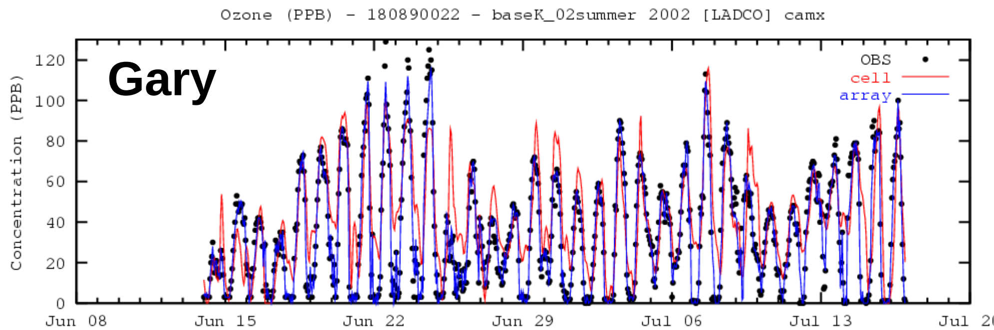


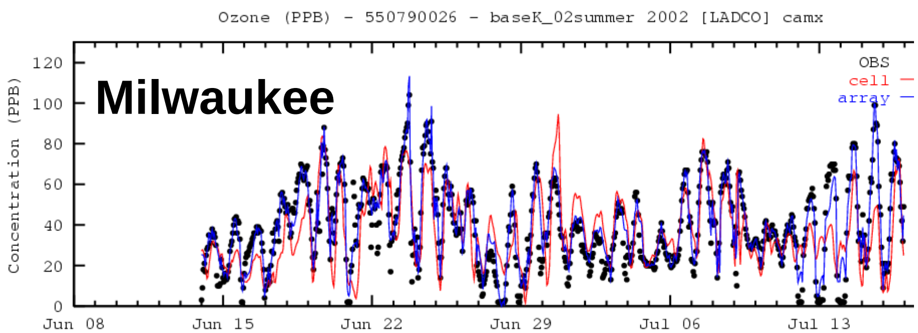


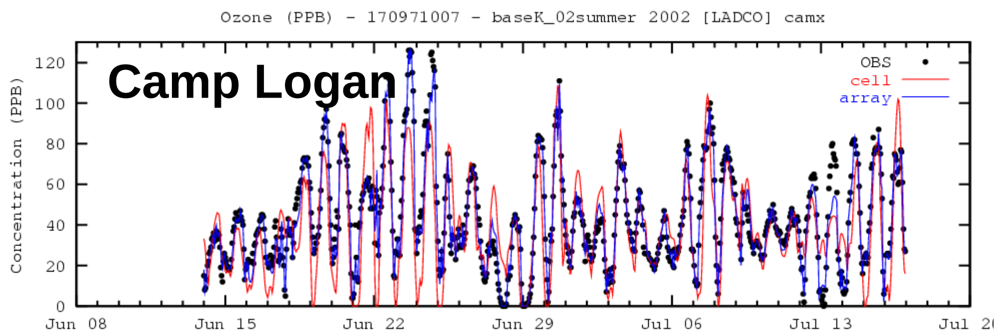


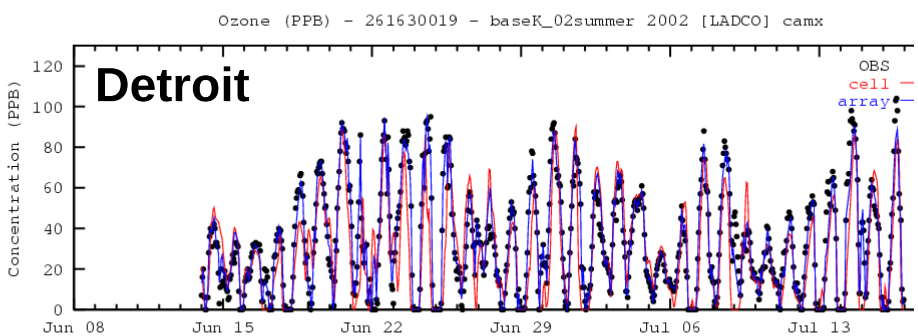
Ozone (ppb)

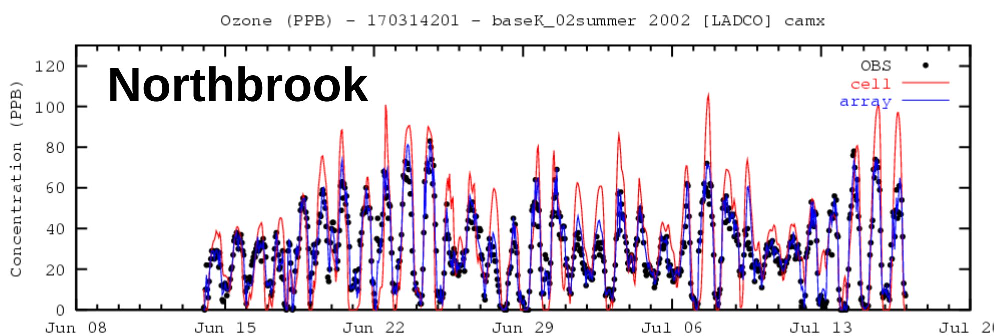

Ozone (PPB) - 170310072 - baseK_02summer 2002 [LADCO] camx
Chicago
OBS
cell
array
Concentration (PPB)
0
20
40
60
80
100
120
Jun 08
Jun 15
Jun 22
Jun 29
Jul 06
Jul 13


Ozone (PPB) - 180890022 - baseK_02summer 2002 [LADCO] camx
Gary
OBS
cell
array
Concentration (PPB)
0
20
40
60
80
100
120
Jun 08
Jun 15
Jun 22
Jun 29
Jul 06
Jul 13
Jul 20


Ozone (PPB) - 550790026 - baseK_02summer 2002 [LADCO] camx
Milwaukee
OBS
cell
array
Concentration (PPB)
0
20
40
60
80
100
120
Jun 08
Jun 15
Jun 22
Jun 29
Jul 06
Jul 13


Ozone (PPB) - 170971007 - baseK_02summer 2002 [LADCO] camx
Camp Logan
OBS
cell
array
Concentration (PPB)
0
20
40
60
80
100
120
Jun 08
Jun 15
Jun 22
Jun 29
Jul 06
Jul 13
Jul 20


Ozone (PPB) - 261630019 - baseK_02summer 2002 [LADCO] camx
Detroit
OBS
cell
array
Concentration (PPB)
0
20
40
60
80
100
120
Jun 08
Jun 15
Jun 22
Jun 29
Jul 06
Jul 13

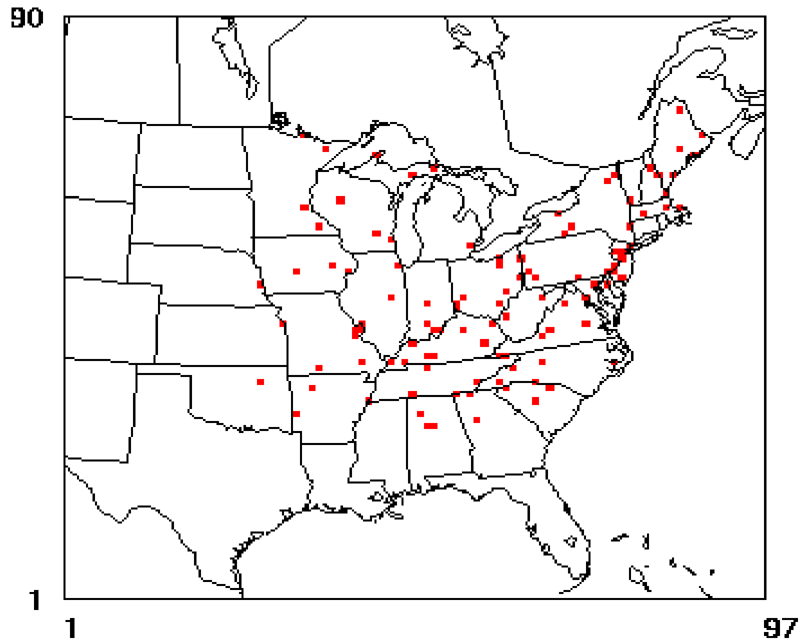

Ozone (PPB) - 170314201 - baseK_02summer 2002 [LADCO] camx
Northbrook
OBS
cell
array
Concentration (PPB)
0
20
40
60
80
100
120
Jun 08
Jun 15
Jun 22
Jun 29
Jul 06
Jul 13
Jul 20

Model Performance

- Metrics consistent with EPA modeling guidance:
  - Bias
  - Error
  - Fractional Bias
  - Fractional Error

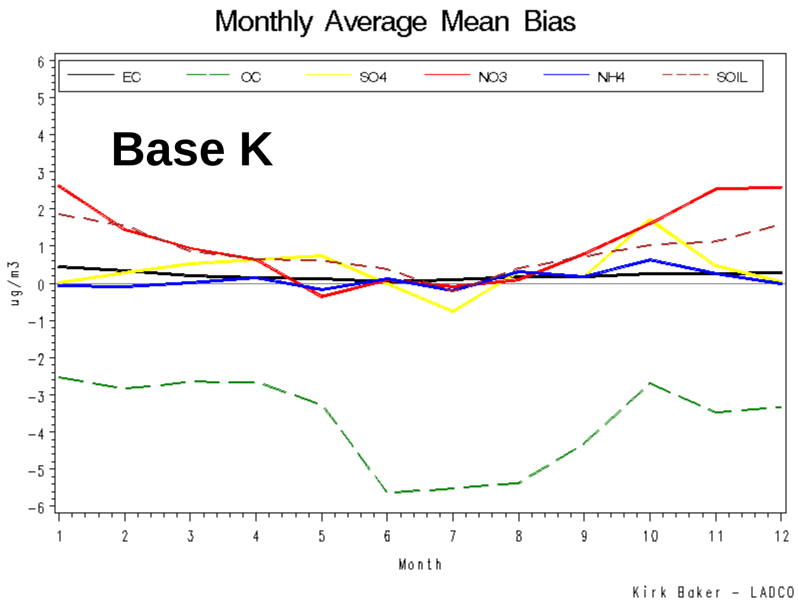
- Model performance using daily average speciated PM2.5 measurements
- IMPROVE, EPA Speciation Trends (from VIEWS)

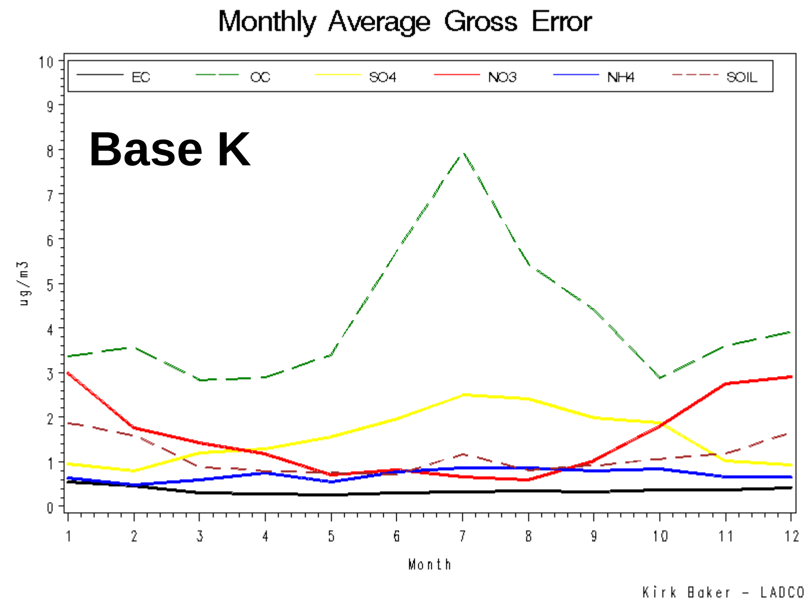
- OM/OC = 1.6 for urban and 2.1 for rural sites

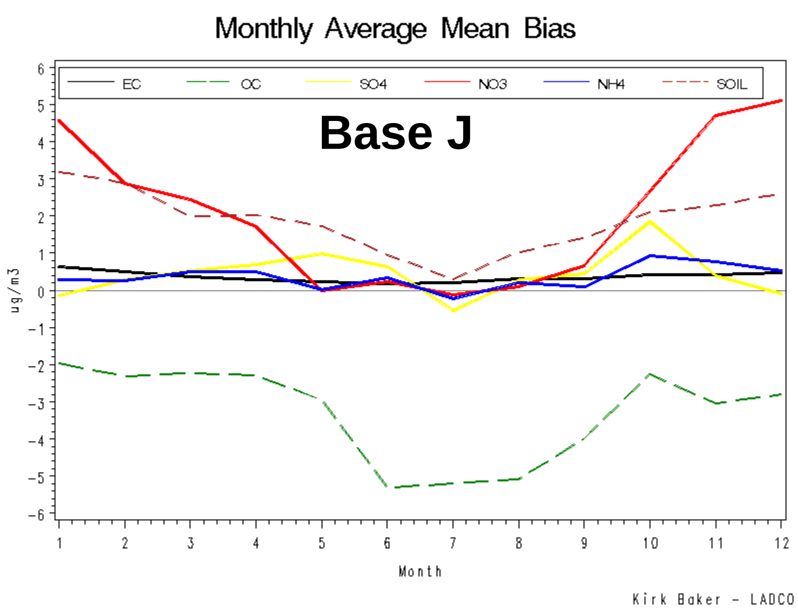


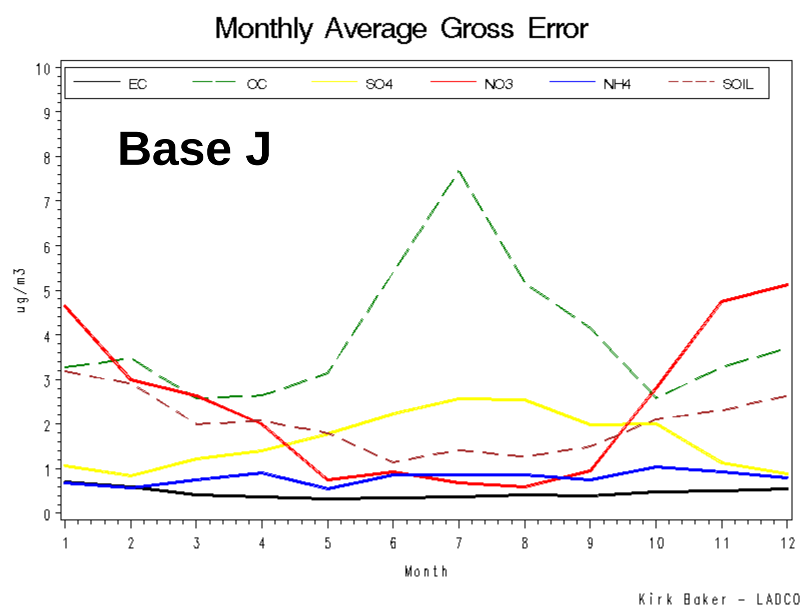
Base K model performance

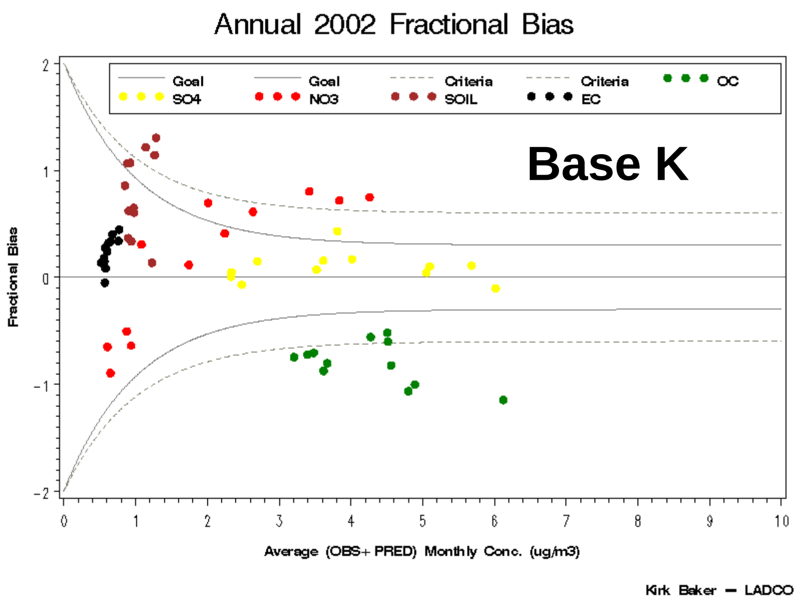
- Performance for nitrate is much better
- Performance for sulfate, OC, and EC is about the same
- Sulfate and EC performance good
- Performance for OC still very poor, especially in the summer months when concentrations are highest

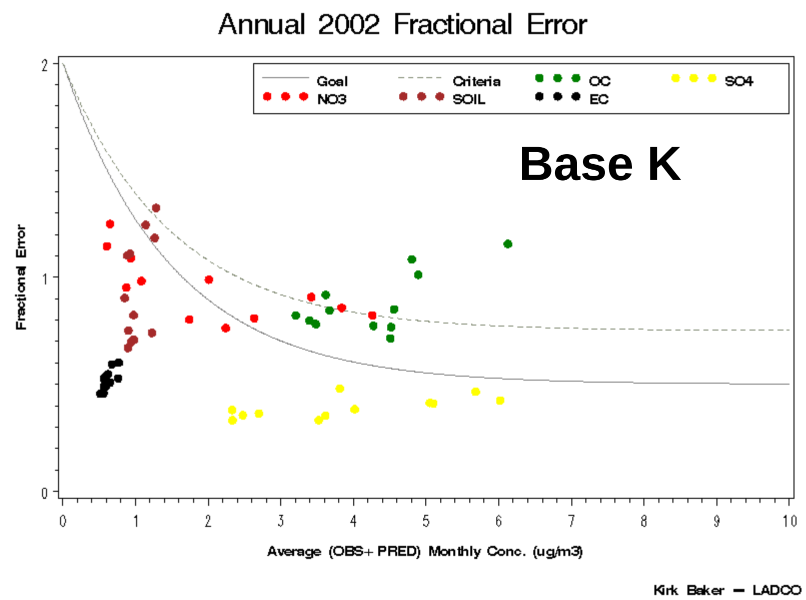

Monthly Average Mean Bias
EC
OC
SO4
NO3
NH4
SOIL
Base K
ug/m3
Month
Kirk Baker - LADCO

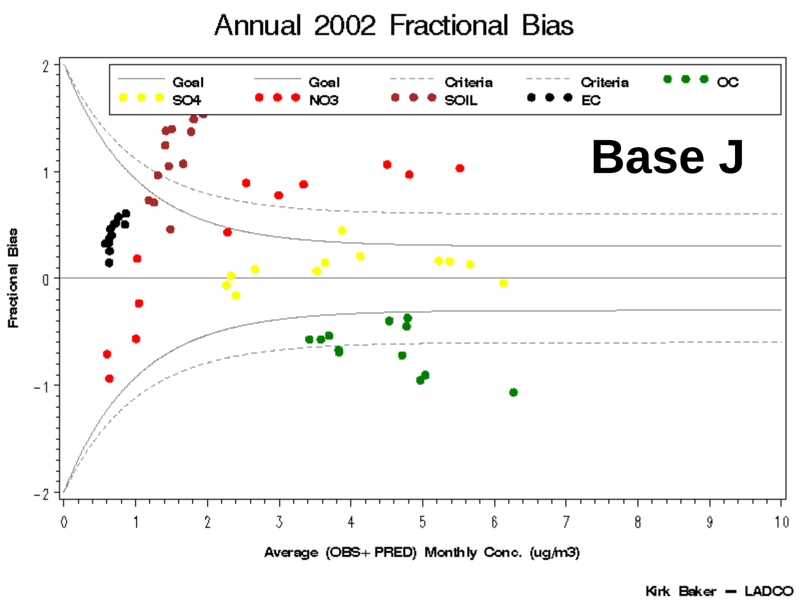

Monthly Average Gross Error
EC
OC
SO4
NO3
NH4
SOIL
Base K
ug/m3
Month
Kirk Baker - LADCO

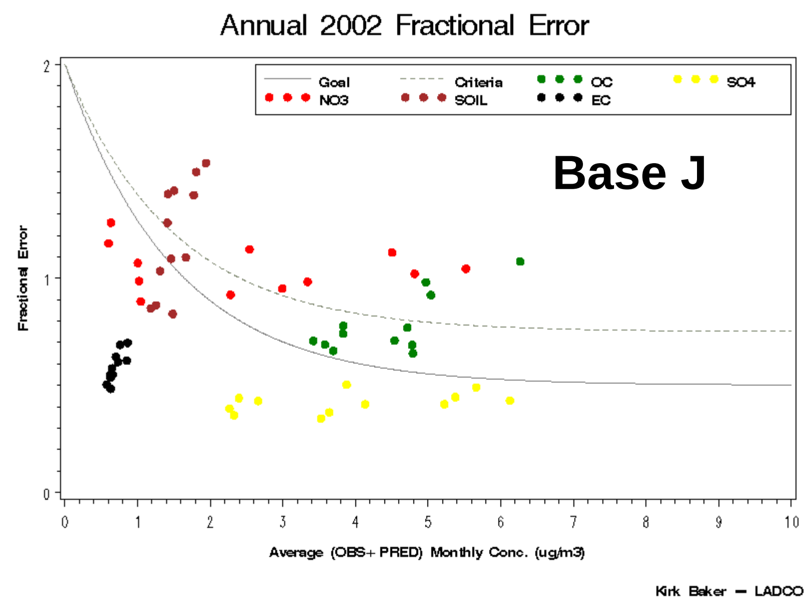

Monthly Average Mean Bias
EC
OC
SO4
NO3
NH4
SOIL
Base J
ug/m3
Month
Kirk Baker - LADCO


Monthly Average Gross Error
EC
OC
SO4
NO3
NH4
SOIL
Base J
ug/m3
Month
Kirk Baker - LADCO

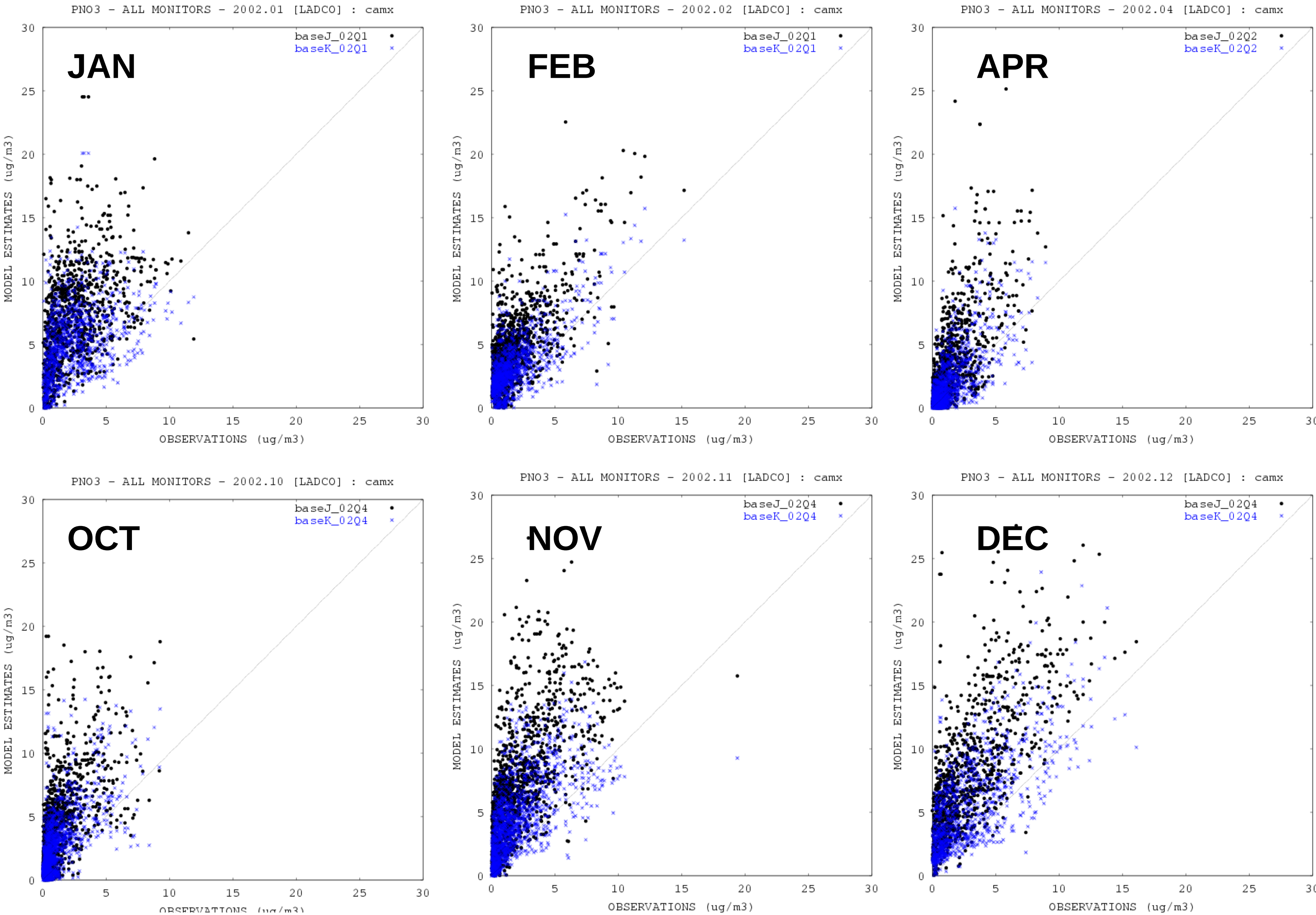

Annual 2002 Fractional Bias
Goal
SO4
Goal
NO3
Criteria
SOIL
Criteria
EC
OC
Base K
Fractional Bias
Average (OBS+PRED) Monthly Conc. (ug/m3)
Kirk Baker – LADCO


Annual 2002 Fractional Error
Goal
NO3
Criteria
SOIL
OC
EC
SO4
Base K
Fractional Error
Average (OBS+PRED) Monthly Conc. (ug/m3)
Kirk Baker – LADCO


Annual 2002 Fractional Bias
Goal
SO4
Goal
NO3
Criteria
SOIL
Criteria
EC
OC
Base J
Fractional Bias
Average (OBS+PRED) Monthly Conc. (ug/m3)
Kirk Baker – LADCO


Annual 2002 Fractional Error
Goal
NO3
Criteria
SOIL
OC
EC
SO4
Base J
Fractional Error
Average (OBS+PRED) Monthly Conc. (ug/m3)
Kirk Baker – LADCO

PM2.5 NITRATE: BASE K v. BASE J



2002 Base K Visibility (DV) against Observations