BEFORE THE ILLINOIS POLLUTION CONTROL BOARD

IN THE MATTER OF:	)	
	)	
PROPOSED AMENDMENTS TO	)	R15-21
SULFUR LIMITATIONS, NITROGEN	)	(Rulemaking- Air)
OXIDES EMISSIONS AND CONTROL	)	(35 ILL. ADM CODE PART 214,217, 225)
OF EMISSIONS FROM LARGE	)	
COMBUSTION SOURCES	)	

NOTICE OF ELECTRONIC FILING

To: John Therriault, Assistant Clerk
Illinois Pollution Control Board
James R. Thompson Center
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PLEASE TAKE NOTICE that on August 28, 2015, I electronically filed with the Clerk of the Pollution Control Board of the State of Illinois **COMMENTS** on behalf of the Sierra Club and the Environmental Law & Policy Center, a copy of which is attached hereto and herewith served upon you.

Respectfully submitted,

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CERTIFICATE OF SERVICE

I, Faith Bugel, hereby certify that I have filed the attached **COMMENTS** on behalf of the Sierra Club and the Environmental Law & Policy Center in PCB R2015-021 upon the attached service list by depositing said documents in the United States Mail, postage prepaid, in Chicago, Illinois on August 28, 2015.

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COMMENTS ON BEHALF OF SIERRA CLUB AND ELPC

I. Introduction

Illinois Environmental Protection Agency ("IEPA") is proposing "Amendments To 35 Ill. Adm. Code 214, Sulfur Limitations, Part 217, Nitrogen Oxides Emissions, And Part 225, Control Of Emissions From Large Combustion Sources" ("Proposed Rule" or "Proposed SO_2 One-Hour Rule"). The primary purpose of these regulations is "to control emissions of sulfur dioxide ('$S0_2$') in and around areas designated as nonattainment with respect to the 2010 $S0_2$ National Ambient Air Quality Standard ('NAAQS')."[1]

Sierra Club and ELPC ("Citizens Groups") offer the following comments on the Proposed Rule. Citizens Groups urge the Board to revise the rule to:

- Remand the Proposed Rule to IEPA to rerun the modeling in a more conservative manner and require additional pollution controls;
- Include the attainment demonstration modeling in this rulemaking to allow full and meaningful public review and comment on this rulemaking;
- Reject the revision to 35 Ill. Adm. Code 225.296(b) that would transfer the exemption from the requirement to install FGD from Joliet 6 to Will County 4;
- Require supplemental limits at Powerton in addition to the limit with the 30-day averaging period; and
- Include enforceable limits for every source for which emissions reductions were modeled.

II. IEPA's Modeling Leaves No Room for Error, and the Provisions of the Proposed Rule Will Not Prevent Future SO_2 1-Hour NAAQS Exceedances

IEPA's modeling creates a concern of higher SO_2 emissions than IEPA accounted for in the modeling. Marginal increases in SO_2 emissions might not pose any real concern if IEPA had relied on a conservative model that established an emissions "cushion" guaranteeing compliance with the NAAQS limit even if there are marginal events. However, IEPA did not do this. Instead, after considering several emission scenarios, the Agency settled on a strategy that represents the

[1] Proposed SO_2 One-Hour Rule, Statement of Reasons at 1 (April 27, 2015), hereinafter "Statement of Reasons".

highest possible emissions across both Nonattainment Areas, without violating the standard. Because IEPA chose to allow emissions at the highest level possible just below the standard, subsequent events that might increase SO_2 emissions at the margins create a disproportional threat to the SO_2 1-Hour NAAQS. Expert testimony identified three such categories of emissions that could place IEPA's modeled compliance with the NAAQS in question.

A. <u>Emissions from Sources Not Subject to Section 214.603</u>

Under the proposed NSIP, IEPA subjects sources listed in Section 214.603 ("603 Sources") to SO_2 emission limitations that apply at all times, even during periods of startup, shutdown, and malfunction ("SSM"). However, most SO_2 sources in both Pekin and Lemont are not subject to the Section 214.603 limitations. Any emissions during SSM events that are higher than those modeled, could increase SO_2 concentrations in both Nonattainment Areas. As above, although such emissions might only lead to a minor increase in total SO_2 concentrations in the region, IEPA's decision to hew closely to the NAAQS 75 ppb limit means that even this small effect could lead to an exceedance of the SO_2 1-Hour NAAQS.

Second, there are sources for which the proposed restrictions would not achieve the full level of modeled emissions reductions. For instance, IEPA's modeling includes predicted emissions reductions of more than 99% at some sources, but the proposed rule sets no hourly emissions limit (in section 214.603) for these sources. We can assume that the ultra-low sulfur fuels requirement applies to these sources because IEPA testimony indicated that there were only a limited number of sources for which reductions were modeled but no restrictions were included in the SIP.[2] The ultra-low sulfur fuels requirement cannot achieve a 99%+ reduction at these sources.[3] As indicated in expert testimony:

> [F]or many sources, the modeling assumes 100% or close to 100% reductions in their allowable emission rates. An over-99% reduction is assumed for 500 sources. An additional 145 sources are assumed to reduce allowable emissions greater than 90% (i.e., between 90 and 99%). Once again, the rulemaking does not indicate how these emissions sources are going to reduce all of their allowable emissions by over 90% to over 99%. Further, and as discussed above, the IEPA provides no support for how these large reductions will be enforceable as a practical manner. If another provision of the rule, such as the requirement to use low-sulfur fuel will automatically result in the low modeled limits, staff should indicate which modeled limits will be achieved through the low-sulfur fuel provisions. It is unlikely, however, that 100% reductions in allowable emissions can be met solely by using lower sulfur fuels in hundreds of sources.[4]

[2] Aug. 4, 2015 Tr. at 206:15-21.
[3] *Id.* at 111-112.
[4] Sahu Testimony at 14; *see also* Aug. 4, 2015 Tr. at 24:4-21.

A 99% or greater reduction cannot be achieved through switching to ultra-low sulfur diesel because the actual reduction in SO_2 from converting from 500 ppm sulfur fuel – i.e., currently available diesel – to 15 ppm sulfur fuel is a 97% reduction.[5]

In short, as this testimony highlights, emissions reductions from the limits in the Proposed Rule were overestimated. As a result, emissions at small facilities, which are a cornerstone of IEPA's modeling assumptions, are likely to exceed the levels modeled. This puts the attainment of the SO_2 1-Hour NAAQS at risk.

B. Additional Emissions from Future Small Sources Receiving Minor Source Permits

Periodically, SO_2 emission sources, including Section 603 sources, will expand to increase their operations in some way. Major modifications to major sources that will involve significant emissions increases will trigger a requirement that the facility obtain a construction (NNSR or PSD) permit. Such projects do not create a risk of emissions negatively impacting the Nonattainment Areas because of the requirements and procedures involved in New Source review. The gap in this system, however, is that new non-major projects at existing facilities or new minor sources, even ones that might have substantial contributions of SO_2 emissions by the facility, do not face the same requirements as major sources. To the contrary, new minor-source permit issuing bodies have no obligation to ensure that new minor sources do not contribute meaningfully to SO_2 concentrations in the region. In fact, these bodies often set up "permits by rule" procedures, whereby minor additions to existing facilities can obtain construction permits without considering impacts on SO_2 emissions. In Illinois, emergency generators can obtain permits from a "permit by rule" as long as their expected annual emissions fall below a 5000 tons of SO_2/year threshold. This is problematic, of course, because even small new minor sources have real, measurable emissions of SO_2, and numerous projects or numerous new sources can pose a threat to the SO_2 1-Hour NAAQS.

C. Additional Emissions During Flaring Events

Finally, flaring of gases, which tends to release large amounts of SO_2 over relatively short periods of time, produces more emissions than IEPA's modeling has assumed.[6] In its modeling for demonstrating compliance with the 1-Hour SO_2 NAAQS, the IEPA has included 54 flares in Illinois and 19 flares in Indiana. All flare emissions modeled appear to be pilot rates, but the rule doesn't contain any requirements that would limit emissions from flares as part of the attainment strategies or attainment demonstration modeling. Modeling pilot emission rates for the flares raise concerns because modeled SO_2 emissions from flares would not reflect actual flaring episodes.

By taking into account only the pilot emissions, IEPA's modeling failed to account for the much higher emissions from flaring that occur on a regular basis. The purpose of a flare at a facility is to safely discharge large quantities of process gases in periodic episodes – either due to planned events such as startup and shutdown or unplanned events such as malfunctions. Higher

[5] Aug. 4, 2015 Tr. at 111-112.
[6] *See* Aug. 4, 2015 Tr. at 27, 109.

emissions occur when the flare is burning off gases at such times when purge and other excess gases are routed to the flares. Thus, short term allowable emissions from flares include not just pilot emissions but also emissions flaring episodes, consistent with facility operations.

One example is the flares at the Citgo Petroleum Corporation Lemont refinery included in the modeling for the Lemont non-attainment. IEPA has included 5 flares from this facility as shown in the Table 1 below.

Table 1[7]

Source Description	**Actual Release Temperature (F)**	**Default Modeled Temperature (K)**	**Flow Rate (acfm)**	**Default Modeled Exit Velocity (m/sec)**	**Heating Value (btu/ft^3)**	**Heat Loss Fraction**	**Emissions (lb/hr)**	**Emissions (g/sec)**
844C-1: Flare	1400	1273	17	20	500	0.55	0.11	0.01386
844C-2: South Plant Flare	1400	1273	43	20	500	0.55	0.11	0.01386
844C-4: Coker 2 Flare Gas Recovery System and Flare	1300	1273	106	20	500	0.55	0.11	0.01386
Loading Rack Flare	123	1273	2741	20	5300	0.55	0.09	0.01134
844C-3: South Plant Flare	1400	1273	43	20	1000	0.55	0.08	0.01008

Flare exit temperatures and flows can vary dramatically during a real flaring event. The fact that these flares have been modeled at “actual” release temperatures of 1300 or 1400 F (for the non-loading rack flares) with the very small flow rates (i.e., only 106 acfm or smaller for the non-loading rack flares) indicates that these numbers do not represent flaring events. The modeled constant exit velocity and the modeled constant heat loss fraction also indicate pilot operations and not flaring events.

[7] IEPA Attainment Demonstration TSD Appendix L.

As a second example, we turn to the BP Products refinery in Indiana. This is the second largest refinery in the country.[8] Table 2 below shows how the six flares at this facility were modeled by the IEPA.

Table 2[9]

Source Description	Physical Release Height (ft)	Effective Release Height (m)	Physical Release Diameter (ft)	Effective Release Diameter (m)	Actual Release Temperature (F)	Default Modeled Temperature (K)	Flow Rate (acfm)	Default Modeled Exit Velocity (m/sec)	Heating Value (btu/ft^3)	Heating Value (Megajoules/m^3)	Gas Flow (million ft^3/hour)	Gas Flow (m^3/sec)	Heat Release Rate (Joules/sec)	Heat Loss Fraction	Emissions (lb/hr)	Emissions (g/sec)
ALKY Flare	Unknown	59.436	Unknown	1.0058	Unknown	1273.15	Unknown	19.995	Unknown	Unknown	Unknown	Unknown	Unknown	0.55	33.4	4.20833
Distillate Desulfurization Unit (DDU) Flare [Emergency Situations]	Unknown	60.96	Unknown	1.2497	Unknown	1273.15	Unknown	19.995	Unknown	Unknown	Unknown	Unknown	Unknown	0.55	33.4	4.20833
Fluidized Catalytic Cracking Unit Flare [Emergency Situations]	Unknown	60.96	Unknown	1.2192	Unknown	1273.15	Unknown	19.995	Unknown	Unknown	Unknown	Unknown	Unknown	0.55	33.4	4.20833
#4 Ultraformer Unit Flare (4UF)	Unknown	60.96	Unknown	1.9812	Unknown	1273.15	Unknown	19.995	Unknown	Unknown	Unknown	Unknown	Unknown	0.55	33.4	4.20833
UIU Flare	Unknown	65.532	Unknown	1.4021	Unknown	1273.15	Unknown	19.995	Unknown	Unknown	Unknown	Unknown	Unknown	0.55	33.4	4.20833
VRU Flare	Unknown	59.436	Unknown	0.6401	Unknown	1273.15	Unknown	19.995	Unknown	Unknown	Unknown	Unknown	Unknown	0.55	33.4	4.20833

That large flaring episodes occur at this refinery, like all refineries, is without question.[10]

[8] http://www2.epa.gov/enforcement/bp-amoco-clean-air-act-settlement.
[9] IEPA Attainment Demonstration TSD Appendix L.
[10] http://www.nwitimes.com/business/local/flare-up-roars-at-bp-whiting-refinery/article_9afb2d3b-9f31-5e76-b6c9-9bcbe0caa60d.html.

IEPA estimated the emission rates for each of these flares identically at 33.4 lb/hr (or 4.208 grams/second), without any information on the actual flow rates. The equal emissions for each flare cannot represent the large, episodic releases from actual flaring episodes and again would suggest emissions during pilot operations only.

Based on these two examples, it is clear that actual and allowable emissions from flaring have been significantly underestimated by IEPA and have not been properly modeled. Emissions when the flare is burning purge, waste, or other non-spec gases are very high for a very short period of time. Specifically, SO_2 emissions during these events would also be much higher than when just the pilot is burning at the flare. This level of SO_2 emissions from flares poses the risk of regular exceedances of the NAAQS in Pekin and Lemont.

D. The Modeling Must Be Rerun in a More Conservative Manner and Additional SO_2 Controls Are Required

As discussed above, underestimated sources in the modeling include diesel sources that will not achieve modeled reductions of 99% or greater, flares that will have much higher emissions during routine operations such as flaring off gases from SSM events when compared to pilot emissions, SSM emissions from sources without hourly limits in Section 603, and normal growth of minor sources.

An additional factor when considering the modeling is weather patterns. IEPA's meteorological data used in the modeling is consistent with USEPA guidelines and abnormal weather patterns alone do not necessarily create cause for concern. However, since the modeling is not conservative and doesn't account for emissions from all sources, abnormal weather patterns do pose a risk here. The modeling does not account for periodical fluctuations in prevailing weather patterns, especially wind directions. Abnormal weather patterns such as these can contribute to NAAQS exceedances in the context of modeling, such as the modeling performed here, that is not conservative.

The IEPA's modeling includes several receptors right on the cusp of non-attainment. For Pekin, this includes the "Fenceline Locations Receptors" at which the total impact from all the sources is 196.2415 ug/m3.[11] For Lemont, this includes the Lockport 11 receptor at which the total impact from all the sources is 191.4823 ug/m3.[12] Consequently, at these receptors the modeled emissions from all of the sources are just barely in attainment.

In sum, cumulative risk is increased by receptors modeled at the cusp of non-attainment, emissions sources that will exceed modeled rates, and unusual weather patterns. Taken together, all these factors create a high risk that the Proposed Rule will not achieve attainment as expeditiously as possible. As a result, deeper cuts must be required of sources such as Will County 4 (as discussed below). In sum, the PCB must require more conservative modeling and

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[11] Pekin Nonattainment Area Spreadsheet, Strategy 1 (December 11, 2014).
[12] Lemont Nonattainment Area Spreadsheet, Strategy 3 Run (December 5, 2014).

additional control of sources in order for the Proposed Rule to assure attainment of the SO_2 1-Hour NAAQS.

III. The Attainment Demonstration Modeling Must Be Available in This Rulemaking

The attainment demonstration modeling should be part of the docket in this rulemaking. The emissions limits and requirements that would be set by this Proposed Rule are based on the attainment demonstration modeling. Consequently, without all the modeling and supporting documentation, it is not possible to fully review and understand the basis for the emissions limits proposed by this rule.

> The Agency's plan is missing its supporting documentation. Although dispersion modeling was used (as required by USEPA) to demonstrate attainment with a set of proposed emission reductions, the only accompanying material that has been published to-date regarding the modeling is the input and output files, and summary spreadsheets. . . . The result is that it is not possible to determine the adequacy and reliability of the model results, and the appropriateness of the Agency's proposed emission reduction plan. [13][14]

While, IEPA did make a draft modeling TSD available to Citizens Groups and their experts, it was not formally made part of the docket such that it was publicly available for review to all interested persons.[15] Numerous other states make attainment demonstration modeling available for review as part of the SIP process. These include, but are not limited to, Michigan, Texas, Oklahoma, Arkansas, Arizona and California. In sum, the attainment demonstration modeling and this rulemaking are inextricably linked such that the modeling must be made publicly available for review as part of this process.

IV. The FGD Exception Should Not be Transferred from Joliet Boiler 5/Unit 6 to Will County Unit 4

As part of the SO_2 1-Hour rule, the IEPA proposes that an exemption from an FGD requirement contained in the Combined Pollutant Standard that applied to Joliet Unit 6/Boiler 5 ("Joliet 6") be transferred from that Unit to Will County Unit 4 ("Will County 4"). IEPA proposes the following revisions (among other changes) to 35 Ill. Adm. Code 225.296(b): "Owners or operators of <u>the other</u> specified EGUs must either permanently shut down, <u>permanently cease combusting coal at</u>, or install FGD equipment on each specified EGU (except

[13] H. Andrew Gray Testimony at 2.

[14] IEPA made this available on July 16, 2015; however, just a little over one week before that expert testimony was due. While that draft TSD did include some of the assumptions and requirements for the modeling, it did not include any of the appendices and also was not formally made part of the docket such that all interested persons and parties could access it. IEPA offered to make those appendices available but only through Citizens Groups sending and IEPA returning a hard drive. As a result, the earliest that Citizens Groups' experts could have obtained that information was July 21, 2015, three days before their testimony was due. As a result, there was inadequate time to review that information and incorporate it into expert testimony.

[15] Aug. 4, 2015 Tr. at 166-168.

Will County 4~~Joliet 5~~), on or before December 31, 2018, unless an earlier date is specified in subsection (a) of this Section." IEPA explains the substitution Will County 4 for Joliet 6 (Boiler 5) as follows:

> During discussions, Midwest Generation also indicated its intent to continue combusting coal at Unit 4 at the Will County station ("Will County 4"). The CPS currently requires that Midwest Generation install flue gas desulfurization ("FGD") equipment on Will County 4 on or before December 31, 2018. 35 Ill. Adm. Code 225.296(b). In light of the significant S02 emission reductions that will result from the conversion of Joliet 6, 7, and 8 and Will County 3 to natural gas or diesel fuel, Midwest Generation requested that Will County 4 be exempted from the requirement to install FGD equipment in lieu of Joliet 6 having such exemption. The Agency's proposal implements this request, both in Part 225 and in the proposed emission limitation applicable to Will County 4 in Part 214.[16]

For the reasons below, this trading of emissions from one facility to another is inconsistent with both the Agency's obligations and past commitments to curb SO_2 emissions from Will County.

A. FGD is Required at Will County 4 for Multiple Air Quality Reasons

The PCB should not allow the FGD exemption for Joliet 6 to be transferred to Will County 4, and should hold Midwest Generation to its commitment in the CPS to install FGD at Will County 4, because reductions at Will County 4 have a different impact on the Nonattainment Area than reductions at Joliet. First, as discussed above, the modeling is not conservative. As a result, the Lockport 11 receptor has a total impact from all the sources of 191.4823 ug/m3.[17] Since the modeling is not conservative, further reductions are required in order to assure that the Lockport 11 receptor stays below the attainment threshold. As discussed below, Will County 4 makes the largest contribution at the Lockport 11 receptor; therefore, FGD at Will County 4 is the most reasonable strategy to achieve reductions at that receptor.

Will County is located in the heart of the Nonattainment Area, whereas Joliet is located relatively further from the center of the harm and located near a different primary receptor, as explained further below. Thus, a pound of reduced SO_2 emissions at Joliet does not equal a pound of reduced emissions at Will County because of the different impact that those emissions have on the Nonattainment Area. And so this proposed tradeoff between Joliet 6 and Will County 4—with reduced emissions at Joliet 6 as the basis for allowing higher emissions at Will County 4—is not reasonable from a policy perspective.

There are two primary differences between Joliet and Will County that make this trade-off problematic. First, the maximum concentration from Joliet and the maximum concentration from Will County occur in different parts of the Nonattainment Area. Joliet is located about six to seven kilometers south of the Nonattainment Area boundary. The peak modeled concentration from Joliet is in the vicinity of the Lockport 1 receptor, as indicated in Table 1 below. The

[16] Statement of Reasons at 12.
[17] Lemont Nonattainment Area Spreadsheet, Strategy 3 Run (December 5, 2014).

Lockport 1 receptor is located in the southwest corner of the Nonattainment Area.[18] On the other hand, Will County 4 has peak modeled concentrations near the Lockport 13 receptor, about six kilometers west of the facility, which also can be seen in Table 3.[19] These modeling results show that Joliet emissions do impact the Nonattainment Area, but to a different degree and at different locations from Will County 4.

Table 3[20]

	Highest contribution for each source across peak modeled design value receptors using allowable emissions[21]
Joliet Unit 6	111 ug/m3 (Lockport 1)
Joliet Unit 7	169 ug/m3 (Lockport 1)
Joliet Unit 8	188 ug/m3 (Lockport 1)
Will Unit 4	159 ug/m3 (Lockport 13)

Second, Will County 4 and Joliet 6 have very different impacts at the peak design value receptor, which is the receptor with the highest impacts that just meets the NAAQS (here, the maximum Lockport 11 receptor). IEPA's attainment demonstration modeling shows that Will County 4 (even after its emissions are reduced by 28%) has a very large impact at the peak design value receptor. The Joliet units, by contrast, contribute only a very small amount at that receptor. According to the model results, allowing Will County to be exempt from controls because Midwest Generation will reduce emissions at Joliet will result in much higher concentrations at the Lockport 11 receptor, as indicated in Table 4 below. This discrepancy between the impact of reductions at Joliet versus reductions at Will County can also be seen from the fact that even with Will County 3 converting from coal, Will County 4 is still contributing 150.4 ug/m3 at Lockport 11, while each unit at Joliet is contributing less than .05 ug/m3 (see Table 4 below).

Table 4[22]

	Modeled impacts using "reduced" emissions at the peak Lockport 11 receptor
Joliet Unit 6	0.033 ug/m3
Joliet Unit 7	0.045 ug/m3
Joliet Unit 8	0.049 ug/m3
Will Unit 4	150.4 ug/m3

[18] This is determined based on the UTM locations provided on each of the modeling run spreadsheets for the Lemont Nonattainment Area. See, e.g., Lemont Nonattainment Area Spreadsheet, Strategy 3 Run (December 5, 2014).
[19] Lemont Nonattainment Area Spreadsheet, Allowable/Permitted Emissions for all Sources, Updated Meteorology (June 17, 2014).
[20] *Id.*
[21] Values in Table 1 represent the highest contributions for each source across the peak modeled design value receptors (due to all sources) within the set of 48 modeled receptor zones. Modeled design values are equal to the 5-year average of the 4th highest daily peak 1-hour SO_2 concentration at each receptor.
[22] Lemont Nonattainment Area Spreadsheet, Strategy 3 Run (December 5, 2014).

At that receptor, a 1 lb/hr reduction from Joliet will result in less than 1/100 the concentration reduction that would occur for the same emission reduction at Will County 4. As presented in expert testimony at the August 4 hearing:

> Emissions from Joliet do not impact the design value location in the same way that the Will County 4. Will County 4 contributes 150 to the highest model receptor and these other sources, which you now told me you're controlling instead contribute 4.6. If you removed all of the 4.6 out, we could get that big of reduction at your peak receptor whereas if we actually controlled Will County 4, we'll make a difference there. That's all I'm talking about. Now, whether or not officially you need to model something to demonstrate attainment is different than the real world. These models are just tools. They don't tell you exactly what's going on.[23]

Even ignoring the facilities' relative impact on the peak design value receptor, however, a reduction of 1 g/s at Joliet is not the same as a reduction of 1 g/s at Will County when looking at air quality near the Will County plant and for the people living near there. As indicated in expert testimony:

> It's the same kind of question we're asking in Will County versus Joliet. Emissions are not equal. A pound of emissions sitting on the edge of your air basin is very different than a pound of emissions being emitted a mile away from your peak receptors or your peak monitors. So it makes a difference.[24]

Importantly, this criticism is both a scientific one and a policy one. Dr. Gray agreed that once the modeling shows attainment, no further reductions are needed for the attainment purposes. However, Dr. Gray's statement does not reflect the fact that the modeling done here was not conservative, as discussed above. We question the Agency's policy decisions to allow significant additional emissions in one part of the nonattainment air basin—and the science supporting those policy decisions. From a scientific perspective, the Will County 4/Joliet 6 tradeoff is not an equal tradeoff. Further, since the modeling is not conservative, it puts the SO_2 1-Hour NAAQS in jeopardy. For these reasons, the PCB should not allow the FGD exemption for Joliet 6 to be transferred to Will County 4 and should hold Midwest Generation to its commitment in the CPS to install FGD at Will County 4.

B. <u>Transferring the Joliet 6 Exemption to Will County 4 Reneges on a Previous Agreement</u>

The PCB also should not allow the substitution of Will County 4 for Joliet 6 in Section 225.296(b) because Midwest Generation agreed to, opted into, and benefitted from the Combined Pollutant Standard ("CPS") of which Section 225.296(b) is part. IEPA in testimony at the hearing on August 4, 2015 made it clear that Midwest Generation negotiated this amendment to Section 225.296(b) exclusively with IEPA.[25] Such an amendment undermines the original

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[23] Aug. 4, 2015 Tr. at 150:5-19.
[24] *Id.* at 170:11-17.
[25] *Id.* at 263:23-264:14.

agreement that parties, including Midwest Generation, made to provide an alternative for the Illinois Mercury and CAIR Rulemakings.

The CPS, originally promulgated in 2006,[26] allows owners of Electric Generating Units ("EGUs") to meet mercury limits less stringent than would otherwise be required as long as they meet certain emission standards and technology requirements for SO_2 and nitrogen oxides ("NOx").[27] Specifically, the CPS gave Midwest Generation a time-limited ability to "opt in" to meeting CPS requirements for SO_2 and NOx,[28] and, in exchange, the right to delay compliance with numeric or input-based mercury limits until at least 2015.[29] CPS mercury control options are less stringent than the requirements of the Illinois Mercury Rule,[30] which applies to EGU owners that do not opt in to the CPS, 35 Ill. Adm. Code 225.291-99, or its parallel, the MPS.

The CPS was a result of negotiations in which Midwest Generation took a lead role. The lengthy record of the CPS rulemaking reveals that numerous parties, including other EGU owners, the Illinois EPA, and several citizens' organizations—including Environmental Illinois, the Environmental Law & Policy Center, Respiratory Health Association of Metropolitan Chicago, and Sierra Club—all took part in the formulation of the CPS.[31] The final 2006 CPS thus represented a laboriously negotiated agreement among diverse parties who identified a mutually acceptable path to address the problems of mercury, SO_2, and NO_X pollution from Illinois' electric generators.

Counsel for Midwest Generation and a witness for the Agency suggest that if PCB rejects

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[26] *In the Matter of: Proposed New 35 Ill. Adm. Code 225 Control of Emissions from Large Combustion Sources (Mercury)*, R06-25 (Dec. 21, 2006). As discussed herein, the MPS was amended in 2009 to, among other things, require Ameren to meet the very standards at issue in this variance proceeding – i.e., a fleet-wide SO_2 standard of 0.25 lb/million Btu by 2015 and a fleet-wide standard of 0.23 lb/million Btu by 2017. *See In the Matter of: Amendments to 35 Ill. Adm. Code 225: Control of Emissions from Large Combustion Sources (Mercury Monitoring)*, R09-10 (June 18, 2009).

[27] *See* 35 Ill. Adm. Code 225.290-299.

[28] *See* 35 Ill. Adm. Code 225.233(e)(3)(c)(iii) and (iv). The MPS includes several requirements for SO_2 and NOx control. For larger EGUs that fire bituminous coal, by no later than December 31, 2009, the EGU was required to install a Selective Catalytic Reduction ("SCR") system for control of NOx and a scrubber for control of SO_2. 35 Ill. Adm. Code 225.233(c)(1)(A). EGU owners must also meet fleet-wide annual and ozone season NOx emission limits, which for Ameren is 0.11 lb/million Btu beginning in 2012, and fleet-wide annual SO_2 emission limits, which for Ameren decline as follows: 0.50 lb/million Btu from 2010-2013, 0.43 lb/million Btu in 2014; 0.25 lb/million Btu in 2015; and 0.23 lb/million Btu in 2017. 35 Ill. Adm. Code 225.233(e)(3).

[29] *See* 35 Ill. Adm. Code 225.292.

[30] The Illinois Mercury Rule required EGUs to meet the same numeric or input-based mercury standards as the MPS in 2009, six years earlier than required by the MPS, without the compliance option of injecting activated carbon at a particular rate for smaller EGUs. 35 Ill. Adm. Code 225.230.

[31] *See generally In the Matter of: Proposed New 35 Ill. Admin. Code 225 Control of Emissions from Large CombustionSources (Mercury)*, R06-25, *available at* http://www.ipcb.state.il.us/COOL/external/CaseView.aspx?referer=results&case=12992) (last visited Aug. 2015). The Citizens Groups were key players in the negotiations leading to the regulatory compromise of the MPS; Illinois EPA specifically sought the Citizen Groups' approval and sign-off on the agreement codified in the standards. The Citizen Groups' participation is reflected in an August 2, 2006 press release from the Office of the Governor that announced the "agreement" underlying the MPS and included statements from the Citizen Groups. *See* http://www.illinois.gov/PressReleases/PressReleasesListShow.cfm?RecNum=5128 (last accessed May 31, 2012).

the exemption for Will County 4, plant owners might be deterred from coming to IEPA with voluntary emissions reductions in the context of a rulemaking.[32] These arguments overlook the fact that the FGD requirement for Will County 4 was an element of a previous agreement in the context of a rulemaking. They also overlook that renegotiating that agreement with the other parties excluded would weaken the power of future voluntary agreements, making it less likely that such agreements will be created.

This proposal is particularly troubling because it is clear that Midwest Generation received a significant benefit under the original deal. Douglas P. Scott, then-Director of IEPA, testified before the U.S. Senate Committee on Environment and Public Works, Subcommittee on Clean Air and Nuclear Safety ("EPW"), as follows, concerning the benefits to industry of Illinois' multi-pollutant approach (both the CPS and the MPS) to regulation:

> The Illinois mercury rule provides substantial flexibility in order to reduce the costs of compliance and risk of noncompliance for power plants. This flexibility includes the ability to meet either a 90% reduction or an output based standard of 0.0080 pounds mercury/GWh, phasing in standards over a period of 3 1⁄2 years with a less restrictive standard in phase one, compliance by averaging of emissions, and the avoidance of installing controls on units that will be shutdown in the near future provided companies make an enforceable commitment to shutdown those units by a date certain.
>
> Additional flexibility is provided via a "Temporary Technology Based Standard" (TTBS) that provides relief for units that install appropriate mercury controls but do not achieve full compliance. Eligible units only need to operate the mercury controls in an optimal manner to comply. This provision is available through June 2015 and can be used by up to 25% of a company's generating capacity.
>
> Companies may choose to voluntarily comply with the MPS or CPS as an alternative to the otherwise applicable requirements of the mercury rule. These provisions provide additional flexibility in regards to mercury control in return for companies achieving significant reductions in the emissions of SO2 and NOx.[33]

As described by Director Scott, Midwest Generation and other companies who opted in to the CPS were afforded the substantial benefit of a flexible phased schedule for compliance with mercury requirements, which is a significant improvement over what would have been an immediate obligation to comply with the mercury standards had they not accepted the CPS bargain. Director Scott concluded, "The result has been a tremendous win-win-win for the environment, public health and the regulated community."[34]

Midwest Generation opted in to the CPS in 2007. Midwest Generation received significant benefits from its negotiated agreement to the CPS obligations. The proposal to

[32] Aug. 4, 2015 Tr. at 214:4-15.
[33] Exhibit 1, Scott Testimony at 6.
[34] Exhibit 1 at 14.

transfer the FGD exemption from Joliet 6 to Will County 4 is an unjustified effort to keep hold of those benefits while dispensing with the one of its obligations.

Given the substantial benefit of flexibility reaped by Midwest Generation and the other Illinois companies who took advantage of the CPS, IEPA strongly emphasized to the Board in 2006 the importance of the "once-in, always in" provision of the MPS regulations—the counterpart to the CPS regulations. The once-in, always-in requirement provides that the units opting in to the CPS comply with it for the lifetime of those units. Without such a requirement, IEPA warned, regulated entities could take advantage of the flexibility benefits of the rule without the concomitant control requirements for other pollutants. This point was made clear in post-hearing comments submitted by IEPA, and signed by IEPA's former Interim Director, John J. Kim:

> Once a company opts-in to the MPS, it is required to comply with the MPS for the lifetime of the affected units, i.e., the MPS is a "once-in, always-in" provision. This provision is necessary to ensure that Illinois and its citizens continue to receive the benefits of the MPS if a company elects to use this alternative to the otherwise applicable standards of the Illinois mercury rule. Otherwise a company might elect to opt-in to the MPS, receive the benefits of mercury control flexibility, and then opt-out of the MPS and comply with the otherwise applicable requirements of the proposed mercury rule absent the additional emissions reduction requirements for NOx and SO2.[35]

Here, Midwest Generation is requesting relief from its obligations under the deal (the FGD requirement at Will County 4 contained in the CPS) after having already taken advantage of the flexibility it secured in return for its previous commitments. In other words, the company is attempting to do exactly what IEPA's own John Kim stated nine years ago must be prohibited.

IEPA suggests that the changes to Part 225 and the proposed limits in Part 214 are inextricably linked.[36] However, when the FGD exception is viewed in isolation, it is not inextricably linked to the limits in 214, and there is no technical reason preventing the Board from rejecting this single revision. When the Board asked that very question of IEPA, IEPA did not link the revision to the FGD exception to any other proposed language.[37] Instead, IEPA relied again on its assertion that it was doing only what is needed for SO_2 1-hour attainment, emphasizing that the reductions that IEPA proposes are adequate to demonstrate attainment. But as established above, IEPA's argument is irrelevant to the question here, and it overlooks the fact that the FGD requirement for Will County 4 was a pre-existing requirement from a different rule. Preserving Will County 4's FGD obligations clearly would not interfere with attainment here. For this reason, the Board should maintain this requirement of Will County 4 independent of SO_2 1-hour attainment.

Assuming, for the sake of argument, that FGD is not needed at Will County 4 for SO_2 1-Hour NAAQS attainment, installation of FGD pollution controls would still deliver

[35] R06-25 (Sept. 20, 2006) (IEPA Post-Hearing Comments), at 47-48 (emphasis added).
[36] IEPA's Responses to the Board's Third Set of Questions at 7 (Aug. 14, 2015).
[37] IEPA's Responses to the Board's Third Set of Questions, Question 67(c), at 11 (Aug. 14, 2015).

improved air quality and corresponding public health benefits. IEPA has argued, and Citizens Groups dispute, that further reductions from Will County are not needed for the purposes of the SO_2 NAAQS compliance.[38] The community around Will County 4, nonetheless, has the right to the pollution reductions and air quality improvements that would stem from this duly negotiated deal that predated the Proposed SO_2 1-Hour Rule—the CPS settlement agreement. The CPS deal required blanket FGD on the whole fleet of units except the single unit that was the oldest, least efficient, and had the shortest lifespan—Joliet 6. Midwest Generation was relieved of its obligation for Joliet Boiler 5/Unit 6 based on the understanding that the future life of that unit was limited. This was not a blanket exemption from the FGD requirement that Midwest Generation could take advantage of for any unit of its choosing. Therefore, the fact that Joliet 6 is retiring should have no bearing on Will County 4's pollution control obligations.

Since Midwest Generation negotiated, opted into, and benefitted from the CPS, the Board must not now allow the Company to undermine that crucial 2006 agreement by relieving it of its obligations to install FGD on Will County Unit 4. As noted above, the agreement underpinning the CPS hinged on the commitment of EGU owners to meet the standard's SO_2 and NO_X limits, and, in return, to be subject to less stringent mercury standards: it was a package deal. One of the stringent SO_2 limits is the requirement to install FGD on every unit in the fleet.[39] Midwest Generation reaped the benefit of less stringent mercury standards for years but wants that benefit without meeting one of the its SO_2 commitments under the rule. Allowing Midwest Generation to do so would breach the agreement that underlies the CPS and undermine the settlement process. And critically, permitting Midwest Generation to escape one of its CPS commitments is not necessary to achieve attainment; in fact, as explained herein, doing so may put attainment in jeopardy. Taken all together, the evidence shows that the Board should hold the company to its previous commitment to install FGD on Will County Unit 4 and not amend Section 225.296(b) to give it an exception.

C. <u>Transferring of the Joliet 6 FGD Exemption to Will County 4 Conflicts with the Regional Haze SIP</u>

Finally, the PCB should reject the change to Part 225.296(b) transferring the FGD exemption from Joliet 6 to Will County 4 because the CPS is part of the Regional Haze SIP, which expressly relies on the requirement for FGD at Will County 4. The Regional Haze Rule requires best available retrofit technology ("BART") on sources subject to the rule.[40] IEPA acknowledges that it has included the CPS in its SIP for regional haze. "Sections of Part 225 directed at emissions of S02 and NOx have been included in SIP submittals to USEPA for regional haze rules."[41] As a result, the proposed changes to the CPS included in the Proposed Rule would undermine the Regional Haze SIP.

[38] Aug. 4, 2015 Tr. at 191:11-14.
[39] 35 Ill. Adm. Code 225.296(b).
[40] Illinois EPA Regional Haze SIP for Illinois at 19 (May 10, 2011).
[41] Illinois Environmental Protection Agency, Technical Support Document for Proposed Rule Revisions Necessary to Demonstrate Attainment of the One-Hour NAAQS for Oxides of Sulfur, at 17 (April 2015) ("TSD").

IEPA is required to submit any changes to Part 225 to USEPA for approval as part of the Regional Haze SIP.[42] IEPA indicates that it intends to submit the revisions to the CPS to the USEPA for approval as revisions to the Regional Haze SIP.[43] Due to the extent to which the Regional Haze SIP relied upon the FGD requirement, however, revising that requirement for Will County out of the SIP risks undermining the SIP. Illinois' Regional Haze SIP submittal included both the MPS and the CPS. "To meet the BART emission reduction requirements for EGUs, Illinois is relying on the MPS/CPS requirements affecting all emission units at sources operated by Midwest Generation, Ameren, and Dynegy . . . ."[44] Nonetheless, both the Regional Haze SIP and the BART TSD make clear that they are not just relying on the system wide emissions limits from the CPS: they also are relying on all additional CPS commitments. "The existing emission reduction requirements <u>and commitments for coal-fired EGUs in Illinois</u> that are subject-to-BART include: the Multi-Pollutant Standard ("MPS") and Combined Pollutant Standards ("CPS") codified in the Illinois Mercury Rule, 35 Ill. Adm. Code Part 225, that apply to Ameren, Dynegy, and Midwest Generation."[45] Thus, Will County 4's commitment is among the policies being relied upon.

In fact, the BART TSD explicitly notes that it is relying on Midwest Generation's commitment to install FGD at Will County Unit 4 and states that the installation of that equipment meets the presumptive BART SO_2 emission limit. "For SO2, Midwest Generation will be installing a scrubber by 2016, which will meet the presumptive BART emission limit for SO2. Midwest Generation will also be replacing the existing electrostatic precipitator on Unit 4 with a fabric filter, which will reduce particulate emissions."[46] The only "BART" unit at Will County is Will County 4,[47] so reductions achieved at Will County through retirement of or natural gas conversions at Unit 3 are not considered as part of the Regional Haze SIP. In its approval of Illinois' Regional Haze SIP, USEPA explicitly relied both on the fleet-wide average emission limits for SO_2 for the Midwest Generation facilities, and on the express commitment to install FGD at Will County 4. "Will County unit 4 is currently controlled with low NO_X burners and OFA. Midwest Generating plans to upgrade the NO_X control to SNCR in 2012 and to add FGD control by 2019."[48][49] In sum, since the Regional Haze SIP, the BART TSD, and the EPA approval of Illinois Regional Haze SIP all relied upon the installation of FGD at Will County 4, the PCB should reject any changes to the FGD requirement for Will County Unit 4 in the CPS.

[42] TSD at 17.
[43] *Id.* at 15.
[44] Illinois EPA Regional Haze SIP for Illinois at 19 (May 10, 2011).
[45] *Id.*
[46] BART TSD at 32.
[47] *Id.*
[48] *Approval and Promulgation of Air Quality Implementation Plans; Illinois; Regional Haze,* 77 *Fed. Reg.* 39943, 39972 (July 6, 2012).
[49] Finally, similar to the SO_2 1-hour NAAQS, regional haze requires a modeling demonstration. That modeling was included in both the Regional Haze SIP and the BART TSD. It included both modeling of baseline emissions and modeling of attainment. "Future year strategy modeling was conducted to determine whether existing ("on the books") controls would be sufficient to provide for attainment of the standards for ozone and PM2.5 and if not, then what additional emission reductions would be necessary for attainment." Regional Haze SIP, BART TSD, Appendix B, Regional Air Quality Analysis at 71. Consequently, the CPS, as "on the books" controls, was presumably included in the modeling. Thus, any changes to the CPS suggest that it would be necessary to redo the modeling for the Regional Haze SIP.

V. The Proposed Rule Must Include Supplemental Limits for Powerton

The PCB should require supplemental limits for Powerton due to the risks posed by surges in SO_2 emissions that would be permissible under the proposed 30-day average. IEPA proposes in its rule an emission limit of 3,452 lb/hr for Midwest Generation's Powerton Station with a 30-day averaging period.[50] The Agency modeled an emission rate of 6,000 lb/hr for Powerton, to account for the longer averaging time in the proposed emission limit.[51] IEPA indicated that it followed the appropriate methodology using the appropriate conversion factor to set the 30-day average for Powerton:

> Illinois EPA, prior to the tiling of this rulemaking with the Board, has consulted with USEPA regarding this 30-day averaging methodology. USEPA was given the same methodology and data set used to determine the 30-day average limit as has been submitted to the Board. USEPA confirmed that Illinois EPA's analysis and methodology were consistent with their published guidance on the subject . . . .[52]

The 30-day average, however, allows for not only the variability in emissions that it is designed to accommodate, but also emission spikes higher than the 6,000 lb/hr that was modeled.

Historically, United States Environmental Protection Agency's ("USEPA") practice was to require that averaging times for SIP emissions limits not exceed the averaging time of the applicable NAAQS.[53] USEPA has gone so far as to say that "source compliance with the 30-day rolling average emission limit . . . does not adequately demonstrate compliance with the short-term NAAQS."[54][55] USEPA shifted from that practice with the SO_2 1-Hour NAAQS. USEPA's guidance on the 1-Hour SO_2 NSIP allows for the use of longer averaging times, but only under certain conditions and upon meeting added burdens.[56]

Despite allowing longer-term averages, USEPA's guidance on 1-Hour SO_2 NSIPs indicates that the use of a longer-term average poses the risk of spikes and that such spikes—if they occur too frequently or spike too high—pose a risk to the hourly NAAQS.

> EPA's general expectation that, if periods of hourly emissions above the critical emission value are a rare occurrence at a source, particularly if the magnitude of the emissions is not substantially higher than the critical emissions value, these periods would be unlikely to have a significant impact on air quality, insofar as they would be very unlikely to occur repeatedly at the times when the

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[50] TSD at 9-10.
[51] *Id.*
[52] TSD at 10.
[53] EPA Guidance for 1-Hour SO_2 Nonattainment Area SIP Submissions at 22 (April, 2014) (hereinafter "NSIP Guidance") *available at* http://www.epa.gov/airquality/sulfurdioxide/pdfs/20140423guidance.pdf.
[54] *See, e.g.*, EPA OAQPS Memorandum "Need for a Short-term Best Available Control Technology (BACT) Analysis for the Proposed William A. Zimmer Power Plant," (Nov. 24, 1986) *available at* http://www.epa.gov/region7/air/nsr/nsrmemos/shrtterm.pdf.
[55] EPA OAQPS SO_2 Guideline Document (Feb. 1994) *available at* http://www.epa.gov/ttn/oarpg/tlpgm.html.
[56] *NSIP Guidance* at 22-40.

meteorology is conducive for high ambient concentrations of SO2.[57]

Powerton's 30-day average poses the exact type of risk to the NAAQS about which USEPA cautioned. The 30-day average (at the outer limit of averaging times that USEPA allowed in the NSIP) does not constrain emission spikes, and those spikes can exceed the critical emission value—that is, the 6,000 lb/hour modeled. For instance, with a 30-day average of 3,452 lb/hour, emissions at Powerton could spike to 9,000 lb/hour one hour per day every day for thirty days, remain slightly below the 3,452 lb/hour limit (at 3,200 lb/hour, to be exact) for the rest of each day, and the source could still achieve the 3,452 lb/hour as a monthly average. Consequently, in order to assure that there will not be an exceedance of the NAAQS through frequent and extreme spikes over the 6,000 lb/hour emission value used in the modeling, there needs to be a supplemental limit on the magnitude and frequency of spikes at Powerton.

Recognizing the danger described above, USEPA's guidance goes on to emphasize the importance of restricting the frequency and magnitude of this very type of spike that Powerton's longer term average allows. USEPA's guidance makes clear that even if agencies used the proper methodology and conversion factor, agencies still must evaluate whether the longer-term average limit will pose a risk to the NAAQS. After USEPA's NSIP guidance discusses the importance of using the proper methodology and conversion factor, the guidance still goes on to discuss the importance of limiting the frequency and magnitude of spikes.

> The second important factor in assessing whether a long term average limit provides appropriate protection against NAAQS violations is whether the source can be expected to comply with a long term average limit in a manner that minimizes the frequency of occasions with elevated emissions and magnitude of emissions on those occasions. Use of long term average limits is most defensible if the frequency and magnitude of such occasions of elevated emissions will be minimal.[58]

If use of the methodology and conversion factor were sufficient to prevent large or frequent spikes, there would be no need to discuss this "second factor." Thus, this additional guidance demonstrates that USEPA does not view a 30-day average based on the appropriate conversion factor and methodology alone as sufficient to protect from spikes that pose a risk to the NAAQS, as IEPA suggested in its presentation to the Board.[59] Similarly, modeling of attainment alone is not sufficient to support a longer-term average. The methodology and conversion factor center on the critical emission value, and it is that critical emission value that is used in the modeling. Consequently, if the methodology and conversion factor will not be sufficient to prevent emission spikes, neither will modeling based on the critical emission value prevent spikes, because the two go hand-in-hand. The fact that the modeling showed attainment is not sufficient justification for rejecting supplemental limits (and/or requirements) in addition to the 30-day emission limit, which is what IEPA suggested to the Board.[60] As USEPA notes, longer-term average limits are only permissible when spikes of emissions above the critical emission value

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[57] *NSIP Guidance* at 24.
[58] *NSIP Guidance* at 33-34.
[59] Aug. 4, 2015 Tr. at 206:22-207:20.
[60] *Id.*

will be (1) rare and (2) limited in magnitude.

In the present case, IEPA failed to include in the rule any additional technical information that assures that the frequency and magnitude of emissions spikes at Powerton will not pose a risk to the SO_2 1-Hour NAAQS. To the contrary, the record reflects that the variability necessitating a 30-day average also necessitates supplemental limits to constrain the magnitude and frequency of spikes that result from that variability. In short, the same reasons that IEPA, and indirectly Midwest Generation, give as the basis for a 30-day average also necessarily suggest a need for supplemental limits:

> [V]ariation in emissions at the Powerton unit, based on the unit type and the control equipment used, can make compliance with an hourly limit difficult. This variability in fired units with dry scrubbers is discussed in the USEPA's guidance for the averaging periods, and this is a type of unit that was expected to need a longer averaging time with a more stringent numerical limit….[61]

This includes variability in emissions due to startups, shutdowns and malfunctions and also due to sulfur content in coal.[62] Additionally, there can be variability due to control equipment not operating.[63]

Where, as here, there is the risk of spikes that threaten the NAAQS, USEPA has emphasized supplemental limits as the appropriate means of restricting the magnitude and frequency of those spikes:

> Consequently, supplemental limits on the frequency and/or magnitude of occasions of elevated emissions can be a valuable element of a plan that protects against NAAQS violations. Limits against excessive frequency *(e.g.*, limitations on the number of times the hourly emissions exceed the critical emission value) and/or magnitude of elevated emissions *(e.g.*, an hourly emissions limit, supplementing the longer term limit, which sets a cap on the magnitude of the peak hourly emissions rate) could further strengthen the justification for the use of longer term average limits.[64]

In particular, USEPA has emphasized the need for supplemental limits for sources that are using control equipment to limit emissions.[65] Possible additional constraints identified by EPA here include requirements regarding the operation of the control equipment (e.g., to be operating some given percentage of the time), setting monthly limits on the number of times that emissions can exceed the critical emission value, and setting a cap on the magnitude of peak emissions—i.e.,

[61] Illinois Environmental Protection Agency's Responses to Board's Pre-filed Questions, R15-21, p. 10-11 (July 7, 2015).
[62] Aug. 4, 2015 Tr. at 73-74.
[63] *Id.* at 118-119.
[64] *NSIP Guidance* at 34.
[65] *Id.*

something above the critical emission value.[66] All of these options should be considered as supplemental limits for Powerton.

The predicted emissions variability at Powerton indicates that supplemental limits are needed to restrict the frequency and magnitude of emissions spikes. USEPA's NSIP Guidance offers multiple options for supplemental limits where emissions spikes pose a threat to the NAAQS. The PCB thus should require some of these supplemental limits at Powerton in addition to the longer-term average provided by the proposed rule.

VI. The Rule Must Include Enforceable Restrictions for Every Source for Which Emissions Reductions Were Modeled

Finally, IEPA's proposed SO_2 1-hour rule doesn't provide sufficient assurances of NAAQS attainment because the rule did not incorporate restrictions that reflect the modeled reductions for all sources. In fact, some sources are not subject to any enforceable emissions reductions. Expert testimony at the hearing delineated modeled reductions from three types of sources: (1) sources with emissions limits included in the Rule; (2) sources subject to the ultra-low sulfur diesel requirements; and (3) sources for which reductions were modeled without enforceable restrictions in the rule.[67] IEPA testimony verified that there are sources for which reductions were modeled, but for which the rule contains no enforceable restrictions.[68] This category of sources creates a concern because the SIP cannot assure attainment of the NAAQS without imposing enforceable restrictions on these sources. IEPA suggests in its testimony that these sources may be subject to enforceable permit limits, but there is no basis for that testimony, and IEPA has failed to provide information verifying this claim to members of the public and interested parties.[69] This is problematic because the SIP is the tool by which attainment is achieved, so the proposed rule itself must contain source limitations for which reductions are required to achieve the NAAQS.[70] The PCB must therefore require the rule to incorporate enforceable restrictions for <u>all</u> sources for which emissions reductions were included in the modeling that demonstrated attainment.

VII. Conclusion

In sum, the Proposed Rule as written does not assure that the SO_2 1-Hour NAAQS will be achieved in the two Nonattainment Areas. The Board must require IEPA to rerun the modeling to ensure that it: (1) accurately reflects the emissions reductions that will be achieved by sources under the rule; (2) includes emissions from flares during all routine flaring events; (3) includes SSM emissions from sources without hourly limits in Section 603; and (4) allows a buffer for normal growth of minor sources. In addition, the Board should make the attainment demonstration modeling publicly available in this rulemaking to ensure that the public has a full

[66] *Id.*
[67] Aug. 4, 2015 Tr. at 108:16-109:11.
[68] *Id.* at 206:15-21.
[69] *Id.*
[70] See 42 U.S.C § 7410 (a)(2) (SIP must " . . . include enforceable emission limitations and other control measures, means, or techniques (including economic incentives such as fees, marketable permits, and auctions of emissions rights), as well as schedules and timetables for compliance, as may be necessary or appropriate to meet the applicable requirements of this chapter.").

and meaningful opportunity to review and comment on all aspects of the proposed rules. Finally, the Board must remedy the defects to the Proposed Rule by rejecting the revision to 35 Ill. Adm. Code 225.296(b) that would transfer the exemption to the requirement to install FGD from Joliet 6 to Will County 4 and thereby put NAAQS compliance at risk; require supplemental limits at Powerton in addition to the limit with the 30-day averaging period; and include enforceable limits for every source for which emissions reductions were modeled.

Respectfully submitted,

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EXHIBIT 1

Written Testimony of Douglas P. Scott, Director, Illinois Environmental Protection Agency, Before the U.S. Senate Committee on Environment and Public Works/Subcommittee on Clean Air and Nuclear Safety On the Issue of: "Oversight: Environmental Protection Agency's Clean Air Regulations – One Year after the CAIR and CAMR Federal Court Decisions" (July 9, 2009)

Written Testimony of Douglas P. Scott

Director, Illinois Environmental Protection Agency

Before the:

U.S. Senate Committee on Environment and Public Works/

Subcommittee on Clean Air and Nuclear Safety

On the Issue of:

"Oversight: Environmental Protection Agency's Clean Air Regulations – One Year after the CAIR and CAMR Federal Court Decisions"

July 9, 2009

Mr. Chairman and Members of the Committee: My name is Doug Scott and I am the Director of the Illinois Environmental Protection Agency. I want to thank Senator Carper and the other members of the Senate Subcommittee on Clean Air and Nuclear Safety for this opportunity to testify on Illinois' regulations to control sulfur dioxide, nitrogen oxides and mercury emissions from the State's coal-fired power plants.

I received a Bachelor's Degree with honors from the University of Tulsa in 1982, and received a graduate Juris Doctor law degree with honors from Marquette University in 1985. I served as Assistant City Attorney and City Attorney for the City of Rockford, Illinois from 1985 to 1995. I also represented the City on a number of environmental issues. From1995-2001 I served as an Illinois State Representative for the 67th District and served on the House Energy and Environment Committee, and was a member of the committee that rewrote the States' electric utility laws. I was elected to the Office of the Mayor of Rockford in April 2001 and served a four-year term and served as President of the Illinois Chapter of the National Brownfields Association. I was appointed as the Director of the Illinois EPA by Governor Rod Blagojevich in July 2005, and have served as Chair of the Air Committee of the Environmental Council of the States (ECOS), the national organization of state environmental agency leaders.

I am pleased to be here to provide testimony on the "three pollutant" approach and Illinois' experience in reaching agreements with our state's three largest coal-fired power plant system owners. My testimony will provide background information and a broad overview of the development of Illinois' multi-pollutant reduction agreements. I will address some of the measures the Illinois EPA took during rule development to ensure that we relied on accurate and current information as we crafted the rule.

Illinois Multi-Pollutant Regulatory Approaches

Illinois is a large industrial state with a population of about 13 million people and a gross state product of $522 billion. Each of these are approximately four percent of the U. S. total and ranks Illinois as fifth among the nation in these categories. Illinois obtains more than 40 percent of its electricity from coal-fired power plants and sits on top of 38 billion tons of coal, giving it the third largest coal reserves in the nation. Coal-fired power plants in Illinois constitute the largest source of man-made emissions of mercury (Hg) and sulfur dioxide (SO_2), and one of the largest sources of nitrogen oxides (NO_x). Illinois is home to 21 large coal-fired plants that operate electric generating units.

Over the last several years in Illinois, exceptional progress has been made in reducing the emissions that contribute to ozone and particulate matter (PM) air pollution, as well as reducing toxic Hg emissions that deposit into and contaminate Illinois' waters and fish. In particular, the Illinois Environmental Protection Agency (Illinois EPA) reached landmark multi-pollutant standard agreements with the three largest coal-fired power plant systems operating in Illinois: Midwest Generation, Ameren and Dynegy. These three companies represent 88% of Illinois' 17,007 megawatts of coal-fired electric generating capacity and account for hundreds of thousands of tons of air emissions each year.

These multi-pollutant standards (MPS) are expected to result in measurable air quality improvements in Illinois and also in regional air quality by dramatically reducing Hg, SO_2, and NO_x emissions from Illinois' coal-fired power plants. The agreed-to multi-pollutant standards are one of the most important environmental and public health advances in Illinois in recent decades. They represent the largest reductions in air emissions ever agreed to by individual companies in Illinois under any context, whether through an enforcement action or regulation.

As a result of the knowledge and experience gained through Illinois' efforts, the Illinois EPA supports a comprehensive national strategy for reducing emissions of multiple pollutants from electric generating units. A comprehensive, integrated approach benefits both regulators and the regulated community. Multi-pollutant approaches should supplement, not replace, the existing Clean Air Act programs such as New Source Review (NSR), Maximum Achievable Control Technology (MACT) standards and regional haze, as well as other important statutory requirements for achieving and sustaining clean air.

In meeting emission goals, the regulated community should be afforded flexibility, where appropriate, which may include an emissions trading mechanism for NOx, and SO_2, but not pollutants where local impacts are of great concern or where concentrated emissions at a local scale may occur – as in the case of Hg. Any multi-pollutant strategy must also ensure that regions, states and localities retain their authority to adopt and implement measures which are more stringent than those of the federal government.

A 3-pollutant approach for controlling the emissions of Hg, SO_2, and NO_x from coal-fired power plants can have numerous advantages over the traditional, single pollutant schemes. For example, a well crafted multi-pollutant standard can increase the protection of public health and the environment, reduce pollution more cost-effectively, and offer greater certainty to both industry and regulators. Since Hg emission reductions can be obtained as a "co-benefit" from the control devices used to reduce SO_2 and NO_x, it makes sense to allow companies the option to synchronize the control of these pollutants, provided that public health and the environment are likewise positively impacted. Whereas the federal Clean Air Mercury Rule (CAMR) single-mindedly tackled mercury emissions, and the federal Clean Air Interstate Rule (CAIR) addressed SO_2 and NOx, Illinois was able to use a multi-pollutant strategy that accomplishes the aforementioned benefits in a unified regulatory framework accounting for planning, engineering, availability of financing and other issues that accompany a multi-pollutant control strategy.

Illinois believes the most feasible method of obtaining reliable emission reductions in a cost-effective manner is through a combination of emission rate based limits along with emissions trading. Although sources under the MPS are not allowed to utilize allowances to meet the numeric emissions standards, sources are free to sell or trade allowances that are generated as a result of emissions being below the allowable emission rates. This provides an incentive for companies to go beyond the reductions required under the MPS in order to recover some of the costs associated with the control measures taken. Moreover, emissions' trading is recognized to provide market incentives for sources to control emissions as far and as fast as reasonably possible. Of note is that emissions trading under a cap and trade program has historically resulted in the highest emitting plants making the deepest reductions in emissions – a key finding that strongly supports the inclusion of emissions trading into any control strategy.

Illinois Multi-Pollutant Agreements

The catalyst for Illinois' agreements was the position taken in early 2006 that Illinois would propose an aggressive mercury regulation focused on cutting mercury emissions by 90% from coal-burning power plants by mid-2009. After the Illinois EPA presented its findings in support of the mercury rule during two weeks of well-attended and hotly contested public hearings, the Agency was approached by Ameren who expressed a desire to work with the Agency toward common goals. Subsequent to long hours of negotiation, an alternative standard was proposed that involved allowing some flexibility in complying with the mercury standards in exchange for commitments to also significantly reduce SO_2 and NOx emissions from Ameren's coal-fired power plants. This initial agreement led to similar discussions and agreements with Illinois' other two large coal burning systems, Dynegy and Midwest Generation.

The agreements reached and memorialized in the Multi-Pollutant Standard (MPS) and Combined Pollutant Standard (CPS) are significant not only for the magnitude of emissions reductions that occur, but also for the rule support that accompanied the agreements. The Illinois mercury rule was vehemently opposed by a unified coal-fired power industry. The initial agreement established that mutual goals were achievable, set the guiding principles, and opened the door for other companies to follow –which they did. Ultimately, the mercury rule was unanimously approved in 2006 by both the Illinois Pollution Control Board and the Joint Committee on Administrative Rules, the two governing oversight bodies for regulations in Illinois.

Both the MPS and CPS provisions provide some flexibility on the timing of mercury reductions in exchange for commitments to make significant reductions in both SO_2 and NOx. All of the provisions include some level of trading restrictions on SO_2 and NOx allowances provided under CAIR. Ameren, Dynegy and Midwest Generation will install a multitude of pollution control equipment on their boilers costing several billion dollars, including wet and dry scrubbers, selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR) devices, and fabric filters. Recent discussions with representatives of Illinois' coal-fired power plants indicate that they are all preparing to meet the requirements of the MPS and CPS, which initiate in 2010. In doing so, a wide array of emissions control equipment costing billions of dollars will come on-line in Illinois over the next several years. Illinois coal-fired power plants have already installed and begun operating numerous halogenated activated carbon injection (ACI) systems for mercury control. The first of many new scrubbers for SO_2 control will begin operation shortly. Fabric filter controls will accompany the installation of many of the scrubbers and result in the co-benefit of particulate matter reductions. Selective catalytic reduction devices and other new NOx controls are being scheduled for installation across Illinois. The shutdown of a few of the older, most polluting electric generating units began in December 2007 with two more units scheduled for shutdown by December 2010.

Illinois Mercury Rule

The Illinois mercury rule is designed to achieve a high level of mercury control, based on Illinois EPA's finding that there exists mercury control technology that is both technically feasible and economically reasonable. Mercury emissions may be reduced through the application of control technology specifically designed to control mercury (e.g., activated carbon injection), or through co-benefit from other control technologies designed to control SO_2, NOx, and PM. Depending on several variables, including coal and boiler type, there are a number of control technologies that will achieve 90+% removal of mercury. Mercury emissions control technology is a rapidly advancing field, with halogenated sorbents being an affordable and effective option for most applications. Although there may be some challenges to achieving 90% removal of mercury for all applications, in almost every case each of these challenges can be overcome or addressed through technology that is economically reasonable and available today.

The Illinois mercury rule provides substantial flexibility in order to reduce the costs of compliance and risk of noncompliance for power plants. This flexibility includes the ability to meet either a 90% reduction or an output based standard of 0.0080 pounds mercury/GWh, phasing in standards over a period of 3 ½ years with a less restrictive standard in phase one, compliance by averaging of emissions, and the avoidance of installing controls on units that will be shutdown in the near future provided companies make an enforceable commitment to shutdown those units by a date certain.

Additional flexibility is provided via a “Temporary Technology Based Standard” (TTBS) that provides relief for units that install appropriate mercury controls but do not achieve full compliance. Eligible units only need to operate the mercury controls in an optimal manner to comply. This provision is available through June 2015 and can be used by up to 25% of a company’s generating capacity.

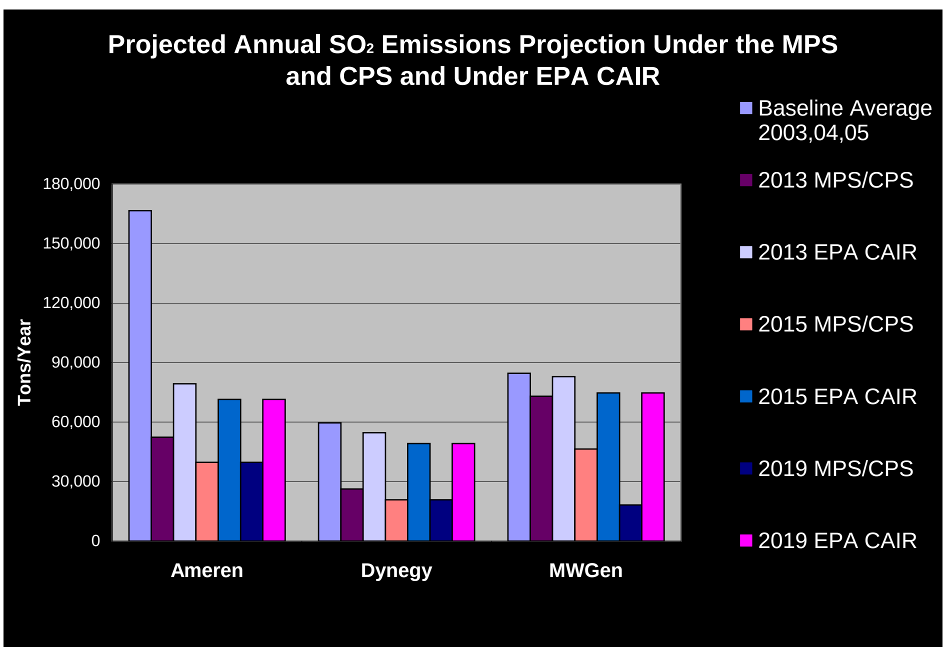
Companies may choose to voluntarily comply with the MPS or CPS as an alternative to the otherwise applicable requirements of the mercury rule. These provisions provide additional flexibility in regards to mercury control in return for companies achieving significant reductions in the emissions of SO_2 and NOx.

Under the MPS and CPS, companies can commit to voluntarily meet numerical emission standards for both NOx and SO_2 and in return are provided additional flexibility in complying with the mercury emission standards. The MPS and CPS provisions also contain restrictions on the trading of NOx and SO_2 allowances provided under CAIR. By regulating the emissions of NOx and SO_2 and restricting the trading of allowances, the MPS and CPS have obvious implications for the proposed CAIR NOx and SO_2 cap and trade program. As modeling has demonstrated, the benefits of these reductions will mostly impact Illinois and a few of the closest neighboring states (i.e., Indiana, Wisconsin and Missouri) with lesser benefits further downwind. While the positive impacts of the reductions are most significant within Illinois and its closest neighbors, Illinois does support emissions trading as the most cost effective controls will be installed and the timing of controls is likely to occur more quickly than under a command and control option.

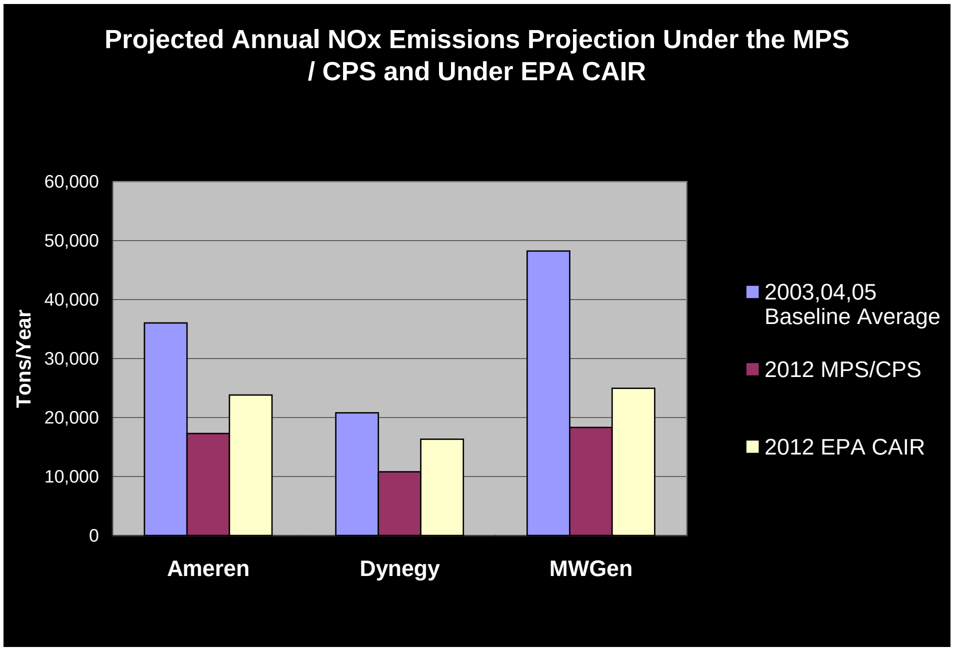
Emission Reductions

The combination of the Illinois mercury rule, CAIR, and the MPS and CPS will have enormous positive impacts, reducing mercury, SO_2 and NOx emissions far beyond the levels required under the federal CAMR and CAIR alone.

Under CAIR, U.S. EPA estimates that coal-fired power producers in Illinois would only have been required to reduce their SO_2 emissions by 34%, not the estimated 76% for Ameren, 65% for Dynegy, and 80% for Midwest Generation required under the MPS and CPS. The emissions of NOx are likewise expected to be reduced beyond the levels obtained by the model CAIR. In addition, both the MPS and CPS contain trading restrictions designed to ensure that the SO_2 and NOx reductions occur in Illinois.



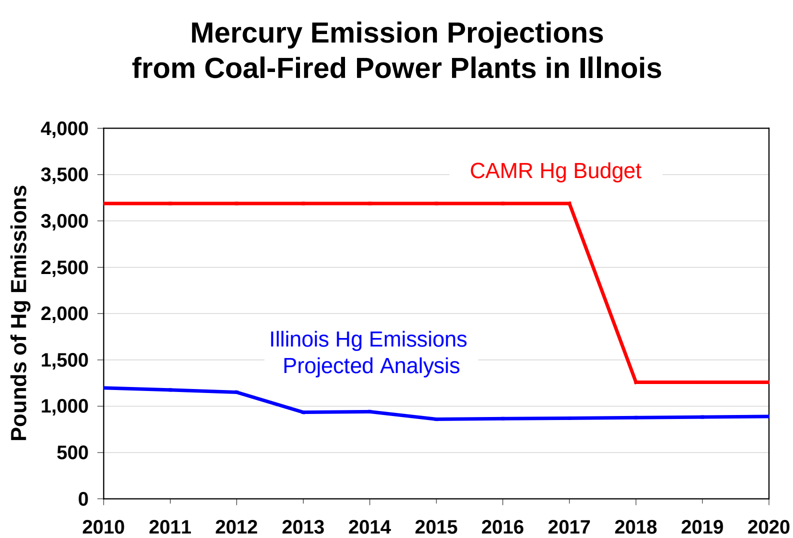
The reductions agreed to under the MPS and CPS for SO_2 and NOx are expected to go a long way toward helping Illinois achieve attainment of the ozone and PM standards. The modeling demonstrates that the emission reductions are very substantial.



The Illinois EPA estimates the total emission reductions from all three power companies at:

- SO_2 = 233,600 tons per year eliminated
- NOx = 61,434 tons per year eliminated
- Mercury = 7,040 pounds per year eliminated

Under CAMR, coal-fired power producers in Illinois would have only been required to reduce their mercury emissions by 47% in 2010 and 78% by 2018, not the 90% reduction by 2009 specified in the Illinois rule. The timing of mercury reductions for



those sources that opt-in to the MPS or CPS is essentially the same, and the amount of reduction is expected to be close to 90%, although the companies will not be required to comply with the 90% reduction requirement on a 12 month rolling basis until 2015. Sources under the MPS and CPS are expected to have mercury emission reductions that exceed the required 90% after 2015 due to the co-benefit reductions achieved from the installation of controls needed to comply with the corresponding SO_2 and NOx standards.

Impacts of Emissions Reductions

Under the agreements between the Illinois EPA and Midwest Generation, Ameren and Dynegy, the decreases in Hg, SO_2, and NOx emissions are estimated to far exceed the reductions required under the federal CAMR and CAIR.

In regards to mercury, over time Illinois expects to see reductions in deposition of Hg to Illinois' lakes and streams and corresponding mercury decreases in Illinois' fish, making those fish caught in Illinois waters safer to eat. There will be several recognized benefits to the State from tighter mercury controls beyond the expected public health benefits that come with a reduction in deposition to Illinois' waters and fish. Such benefits include support for existing jobs and the potential for additional jobs resulting from the installation and operation of additional pollution control devices.

The benefits of removing SO_2 and NO_x are well established and most notably will result in reductions in both particulate matter and ozone. SO_2 is a precursor to particulate matter and NO_x is a precursor to both particulate matter and ozone. Particulate matter related annual benefits include fewer premature fatalities, fewer cases of chronic bronchitis, fewer non-fatal heart attacks, fewer hospitalization admissions (for respiratory and cardiovascular disease combined) and should result in fewer days of restricted activity due to respiratory illness and fewer work loss days. Moreover, there should be health improvements for children from reduced upper and lower respiratory illness, acute bronchitis, and asthma attacks.

Ozone health-related benefits are expected to occur during the summer ozone season and include fewer hospital admissions for respiratory illnesses, fewer emergency room admissions for asthma, fewer days with restricted activity levels, and fewer days where children are absent from school due to illnesses. In addition, there should be ecological and welfare benefits. Such benefits include visibility improvements; reductions in acidification in lakes, streams, and forests; reduced nutrient replenishing in water bodies; and benefits from reduced ozone levels for forests and agricultural production.

CAMR and CAIR Vacatur Impact on Illinois Regulations:

On February 8, 2008, the United States Court of Appeals for the District of Columbia Circuit vacated the federal CAMR. The Illinois mercury rule is separate from the federal CAMR and therefore the vacatur of CAMR had minimal impact on the Illinois rule. However, this court action raised concerns regarding the status of certain federal provisions dealing with the monitoring of mercury emissions. Given the uncertainty surrounding federal mercury monitoring provisions, the Illinois EPA determined that a revision to the Illinois mercury rule was appropriate. The revisions focused on the methods used to measure or monitor mercury emissions, and did not include any revisions to the control standards themselves. The rule was amended to allow a source to demonstrate compliance for a three year period using stack testing. The Illinois mercury rule remains in full effect and all Illinois companies began complying with the rule on July 1st of this year.

In July of 2008, the U.S. Court of Appeals for the District of Columbia Circuit (DC Court of Appeals) vacated the CAIR rule in its entirety. After entertaining motions for reconsideration from the parties, on December 23, 2008, the same court issued an opinion stating that the federal CAIR was remanded to U.S. EPA without vacatur. U.S. EPA subsequently confirmed that it has begun implementation of CAIR starting January 1, 2009. Illinois CAIR is in full effect. For a number of reasons, the vacatur and reinstatement of Phase I of CAIR have had minimal impact on Illinois sources and the MPS and CPS remain in effect. However, for the reasons discussed below, Illinois strongly favors federal multi-pollutant legislation to “remedy” the flaws in CAMR and CAIR.

The decision of the DC Court of Appeals vacating CAIR in part, i.e., vacating Phase II of CAIR but reinstating Phase I of CAIR, has thus far had minimal impact on Illinois. CAIR Phase I required reductions up until the beginning of CAIR Phase II in January 1, 2015. Although Illinois relied upon CAIR Phase I as part of our 8-hour ozone (85 ppb) and annual PM2.5 attainment plans, air quality in Illinois' two 8-hour ozone (85 ppb) and annual fine particulate matter nonattainment areas has improved to a very significant degree without these expected reductions. As a result, all but one monitor is in attainment for these standards, and it is expected to be in attainment in 2012. Because the MPS and CPS result in significant reductions before 2015, Illinois is not dependent on CAIR Phase II reductions for the newest 8-hour standard (75 ppb) or the newest daily fine particulate matter standards, and for which attainment plans are not yet due. Despite the improvement in air quality, Illinois would have much more significant problems in demonstrating attainment in it state implementation plan if CAIR Phase I was not reinstated.

There is some concern that Illinois coal-fired power plants may delay or cancel some controls that were being installed to comply with CAIR Phase I due to the loss of value in SO_2 and NOx allowances. The market value of these allowances is uncertain, because there is controversy over whether the DC Court of Appeal's opinion has disallowed an emissions trading program. As a result, companies have no incentive to go beyond the reductions required by CAIR Phase I because the incentive to install controls early due to the cost recovery benefit of the allowances obtained is removed. Also, many companies have a significant number of banked allowances available for their use or for sale, and these banked allowances will be depleted rather than companies meeting the "emissions cap" through installation and operation of pollution control equipment, perhaps even to the extent of not operating existing or recently installed controls. However, we believe the MPS and CPS should keep Illinois sources on track for installation and operation of the planned control devices and reductions.

After the vacatur of CAIR, the Northeast and Midwest states began a process, called the "State Collaborative Process", the stated intent of which was to develop a multi-pollutant strategy to achieve levels of NOx and SO_2 reductions from the electric utility sector in the 28-state CAIR region as expeditiously as possible that would remedy CAIR's flaws in accordance with the Court's July 11, 2008 opinion and satisfy the requirements of the Clean Air Act to attain the 1997 national ambient air quality standards (NAAQS) for ozone and PM. While significant progress was made in developing a framework for a CAIR replacement rule, no final recommendation to USEPA has yet been developed. The participating states disagree over the level of reductions that should be required, whether best available controls should be required on every power plant or just the larger/largest units, the timing of controls, whether emissions trading (or even intra-state emissions averaging) is allowable under the Court's decision, and whether a replacement rule can forestall Section 126 petitions under the Clean Air Act.

It is Illinois' experience that emissions trading will result in the greatest amount of reductions at the lowest cost. More importantly, emission trading will encourage companies to install controls earlier, and go beyond required reduction levels, as compared to a command and control strategy. Under a command and control strategy, the regulatory compliance deadline must be set such that there is 100% assurance that every affected source will be able to comply in consideration of the time necessary for planning, engineering and construction deadlines. In other words, there must be sufficient availability of engineering firms, control equipment and construction companies to plan, engineer, build and install all of the pollution control equipment required for compliance. Such a regulatory compliance date would certainly be difficult to establish and likely result in far fewer reductions in the near term when compared to an approach that includes emissions trading. Also, the construction season in many of the affected CAIR states is limited to a 7 to 8 month window, when electric demand is at its highest, further complicating this approach.

In addition to regulatory compliance deadlines, sources (and the states) must be concerned with power outages. In Illinois' opinion and experience in negotiating the MPS and CPS, within the CAIR region, it is not practical (and may not be possible) to retrofit all coal-fired power plants of any significant size (e.g., 25 MWe or more) in the same 3-year window (or even 5-year window). A command and control strategy necessarily sets a date certain for compliance for each affected and similarly situated source. Emissions trading will allow those time frames to be compressed, as source by source compliance is not required.

As Illinois discovered during its MPS and CPS negotiations, there are very significant costs associated with installing pollution controls of the magnitude negotiated under Illinois' rules – estimated in excess of 3 billon dollars. While this cost may be seem small on a kilowatt hour basis, these companies must obtain a rate increase if they are in a regulated state or financing if they are in a deregulated state like Illinois. The ability to obtain a rate increase or financing for these projects is uncertain and takes time, which must be accounted for in a compliance date for any command and control strategy. Emissions trading will allow those time frames to be compressed as well, as source by source compliance is not required.

The vacatur of both CAMR and CAIR emphasizes the high risk associated with moving forward with federal regulations subject to widespread opposition and controversy. Federal regulations will almost certainly be challenged, potentially resulting in further delay of a vital strategy for the states to achieve attainment of the federal air quality standards. Section 126 petitions will surely also be filed by any state that believes its neighbor and upwind states could do more to address nonattainment, even if the complaining state's air quality issues are largely a result of emissions from its own sources (area, mobile and point) and even if the targeted other state(s) has done more to address emissions from its coal-fired power plants than the complaining state. Section 126 petitions will use precious resources that are needed to address the newest recent daily PM2.5 standard, the revised 8-hour standard (75 ppb), the newest lead standard, and the recently-announced, revised NO2 standard. Federal multi-pollutant legislation represents the best option for addressing the points of disagreement among the states, without being bound by interpretations of the scope and flexibility provided under the 1990 Clean Air Act amendments, and in a way that best serves the goal of obtaining the greatest reductions in SO_2, NOx and Hg, in the shortest possible time frame, while taking into account electric costs and reliability.

In conclusion, the multi-pollutant approach taken in Illinois for controlling the emissions of Hg, SO_2, and NO_x from coal-fired power plants has numerous advantages. Whereas the federal CAMR focuses solely on mercury emissions, and CAIR concentrates on SO_2 and NO_x, Illinois' has taken a combined approach that exceeds the goals in the context of a single regulatory framework, accommodating engineering and construction issues and outage schedules, as well as financing issues. The result has been a tremendous win-win-win for the environment, public health and the regulated community.

Multi-Pollutant Standard & Combined Pollutant Standard – Required Emissions Rates and % Reductions

	CAIR in IL[1]	CAIR in IL[1]	Midwest Generation		Ameren		Dynegy	
	Emission Rate (lbs/mmbtu)	% Reduction	Emission Rate (lbs/mmbtu)	% Reduction	Emission Rate (lbs/mmbtu)	% Reduction	Emission Rate (lbs/mmbtu)	% Reduction
SO2								
2010					0.50	52%		
2013	0.50	31%	0.44	13.7%			0.24	56%
2014			0.41	19.6%	0.43	56%		
2015	0.45	34%	0.28	45.1%	0.25	76%	0.19	65%
2016			0.195	61.8%				
2017			0.15	70.6%	0.23	78%		
2018			0.13	74.5%				
2019	0.45	34%	0.11	78.4%[2]	0.23	78%	0.19	65%
NOx								
Annual – 2012	0.15	44%	0.11	62%[3]	0.11	52%	0.10	48%
Annual - 2015	0.12	55%	0.11	62%[3]	0.11	52%	0.10	48%
Seasonal - 2012	-	-	0.11	51%	0.11	22%	0.10	25%

[1]CAIR emission rate numbers from page 5 of the June 28, 2005 USEPA presentation to LADCO (http://www.ladco.org/reports/rpo/Regional%20Air%20Quality/June28_2005/June-Workshop/CAIR%20LADCO%20.pdf).
Percent reductions from the USEPA website that provides CAIR reductions expected in Illinois (http://www.epa.gov/cair/il.html).
Emissions used for calculations are from Clean Air Markets Divisions of USEPA.

[2]80% including planned shutdowns.

[3]68% including planned shutdowns.

Note: Ameren SO2 rates reflect changes to allowable rates as contained in proposed revision to Illinois mercury rule.

Percent Mercury Reductions from CAMR, Illinois Combined Pollutant Standard (CPS) and Multi-Pollutant Standard (MPS)

Beginning Period	CAMR	Midwest Gen - CPS	Dynegy - MPS	Ameren - MPS
Mid 2008		21%		
Mid 2009		84% (ACI installed on most units)	(ACI installed on most units)	(ACI installed on most units)
2010	47%		86%	86%
2011		90% (ACI on all units)		
2013[1]		90%	90%	90%
2015[2]		>90%	94.4%	93.5%
2018	78%	95%		

[1]All units have controls installed that are designed to achieve 90% reduction in mercury emissions.

[2]Several units at plant have combination of Scrubber, Baghouse, SCR and/or ACI and many units will achieve greater than 90% reduction in mercury emissions.

All numbers are Illinois EPA estimates.