BEFORE THE ILLINOIS POLLUTION CONTROL BOARD

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

NOTICE

To: John Therriault, Assistant Clerk
Illinois Pollution Control Board
James R. Thompson Center
100 West Randolph, Suite 11-500
Chicago, Illinois 60601-3218

PLEASE TAKE NOTICE that I have today filed with the Office of the Pollution Control Board the Illinois Environmental Protection Agency's Responses to the Board's Third Set of Questions, a copy of which is herewith served upon you.

Respectfully submitted,

ILLINOIS ENVIRONMENTAL
PROTECTION AGENCY

By: /s/ Dana Vetterhoffer
Assistant Counsel

DATED: August 14, 2015
1021 N. Grand Ave. East
P.O. Box 19276
Springfield, IL 62794-9276
(217) 782-5544

BEFORE THE ILLINOIS POLLUTION CONTROL BOARD

IN THE MATTER OF:	)	
	)	R15-21
AMENDMENTS TO 35 ILL. ADM. CODE	)	(Rulemaking-Air)
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ILLINOIS ENVIRONMENTAL PROTECTION AGENCY'S RESPONSES TO BOARD'S THIRD SET OF QUESTIONS

The Illinois Environmental Protection Agency ("Illinois EPA" or "Agency"), by its attorney, offers the following responses to the "Board and Staff Questions for Third Hearing," dated August 3, 2015. The Agency also attaches "updated" versions of Parts 214 and 225, as requested by the Board at the third hearing.[1] These versions set forth the Agency's original proposal, plus any changes subsequently recommended by the Agency, or proposed by the Board and agreed to by the Agency.

60. IEPA's Technical Support Document (TSD) Table 4 provided information on SO_2 emissions from Midwest Generation units for 2014, 2017, and 2019. TSD at 17. For each calendar year 2012, 2013, and 2014, provide the following information for each of Joliet Units 6, 7, and 8, and Will County Units 3 and 4:

a. actual annual SO_2 emissions in tons per year

	2012	**2013**	**2014**
Joliet 6	2,210.5	3,059.1	2,553.9
Joliet 7	5,361.7	6,166.2	5,429.9
Joliet 8	5,787.1	6,237.1	4,816.0
Will County 3	2,848.4	3,030.4	3,144.1
Will County 4	5,436.7	5,805.8	5,804.6

[1] The Agency is not providing an updated version of Part 217, as the Agency has not recommended any changes to its original proposal. Also, the Agency completely removed Section 214.301 from the updated version of Part 214, as the Agency no longer proposes amending such Section in this rulemaking.

b. rated capacity

	Nameplate capacity (MW)
Joliet 6	360.4
Joliet 7	660
Joliet 8	660
Will County 3	299.2
Will County 4	598.4

c. total MWHs generated

	Total generation (MWh)		
	2012	**2013**	**2014**
Joliet 6	1,104,453	1,551,159	1,302,668
Joliet 7	2,709,570	2,976,330	2,888,705
Joliet 8	2,729,524	2,992,761	2,445,594
Will County 3	1,112,405	1,329,038	1,444,119
Will County 4	2,364,927	2,808,873	2,917,279

d. annual capacity factor

	Annual capacity factor								
	Assumed 8760 hours			**Actual operating hours**			**Capacity per hour**		
	2012	**2013**	**2014**	**2012**	**2013**	**2014**	**2012**	**2013**	**2014**
Joliet 6	0.350	0.491	0.413	6195.3	7923.3	5722.5	0.495	0.543	0.632
Joliet 7	0.469	0.515	0.500	7242.9	7829.6	7140.4	0.567	0.576	0.613
Joliet 8	0.472	0.518	0.423	7719.1	8128.8	6205.5	0.536	0.558	0.597
Will County 3	0.424	0.507	0.551	8099.3	7897.5	7428.0	0.459	0.562	0.650
Will County 4	0.451	0.536	0.557	7774.5	8224.3	7333.8	0.508	0.571	0.665

e. average heat rate

	Average heat rate (mmBtu per operating hour)		
	2012	**2013**	**2014**
Joliet 6	1,797.6	1,988.2	2,220.0
Joliet 7	1,879.0	1,938.9	2,019.4
Joliet 8	1,869.3	1,879.9	2,004.1
Will County 3	1,577.1	1,890.8	2,274.8
Will County 4	3,084.0	3,404.4	4,087.6

f. annual heat input

	Annual heat input (mmBtu)		
	2012	**2013**	**2014**
Joliet 6	11,136,575	15,753,074	12,703,833
Joliet 7	27,218,565	30,361,738	28,837,853
Joliet 8	28,859,289	30,562,988	24,873,378
Will County 3	12,772,999	14,932,280	16,897,421
Will County 4	23,976,409	27,998,597	29,977,167

61. Provide the following information for each of Joliet Units 6, 7, and 8, and Will County Units 3 and 4, as used in IEPA's modeling to demonstrate attainment with the one-hour SO_2 NAAQS.

a. SO_2 emission rate in lb/hr

RESPONSE: The Agency modeled the lb/hr limits proposed in Section 214.603, as follows:

Joliet Unit 6	**189.82 lb/hr**
Joliet Unit 7	**323.29 lb/hr**
Joliet Unit 8	**342.15 lb/hr**
Will County Unit 3	**145.14 lb/hr**
Will County Unit 4	**6520.65 lb/hr**

b. rated capacity

RESPONSE: The dispersion modeling does not take a unit's electrical capacity into account.

c. total MWHs generated

RESPONSE: The dispersion modeling does not take a unit's total electrical generation into account.

d. annual capacity factor

RESPONSE: The dispersion modeling does not take a unit's capacity factor into account.

e. average heat rate

RESPONSE: The dispersion modeling does not take the average heat rate of a unit into account.

f. annual heat input

RESPONSE: The dispersion modeling does not take a unit's annual heat input into account.

g. fuel utilized and sulfur content of that fuel

RESPONSE: In order to make assumptions about achievable allowable emissions for the modeling, the following fuels were assumed: At Will County 4, coal was assumed, although no assumptions about the fuel sulfur content were made, only the unit's lb/hr emission rate. At the Will County 3, and Joliet 6, 7, and 8 units, the modeling assumed use of low sulfur diesel with a sulfur content of 500 ppm. This was used as an extremely conservative approach even though it is expected that the Joliet units will utilize natural gas as a fuel (most likely with ultra-low sulfur diesel as a backup), and that the Will County 3 unit will not be in operation.

62. In response to Board Question 49, IEPA states that "It would be difficult to determine the precise [SO_2] emission rate at Will County 4 without the Agency's proposed amendments…the unit's emissions would be regulated by the fleet-wide average 0.11 lb/mmBtu [SO_2] emission rate in 2019, regardless of whether the unit installs FGD equipment." PC5 at 8.

a. In general terms, provide a typical percentage range of SO_2 reductions that a coal-burning electric generating unit might realize from the installation of appropriately sized FGD equipment in terms of lb/hr and tons/year.

RESPONSE: There are many types of FGD equipment, with varying sulfur removal efficiencies. Assuming that the Board's inquiry relates to trona injection, there are no "typical" emission reductions levels; that analysis is unit-specific, and dependent upon the type of fuel combusted, the sulfur content of the fuel, and any other control devices being utilized by the unit.

Despite the difficulty in estimating emission reduction levels, a typical range may vary from as low as 40% up to 80% reduction in SO_2 emissions by dry sorbent injection systems like those being installed at other Midwest Generation units.

b. Based on actual 2012, 2013 and 2014 annual SO_2 emissions requested above for Will County 4, estimate a typical range of SO_2 reductions that appropriately sized FGD equipment could have provided for those years in terms of tons/year. Address whether such an estimate can be made in terms of lb/hr, and, if so, what the reduction might be.

RESPONSE: It is important to note that the CPS does *not* require that FGD equipment achieve a particular SO_2 removal efficiency at any specific unit. So, while an 80% reduction in SO_2 emissions might be achieved, that is the high end of a range of control efficiency, and nothing in the CPS requires such a reduction level. The CPS requires only the installation of FGD on Will County 4, and that Will County 4 and the other CPS units comply with the overall fleet-wide group average SO_2 emission rate.

c. In general terms, provide a typical cost estimate for installation of FGD equipment, whether in terms of \$/mmBtu or \$/SO_2 tons removed or other appropriate units.

RESPONSE: It is difficult to provide an installation cost estimate in terms of \$/mmBtu or \$/SO_2 tons removed. Based on the information currently available to the Agency, cost estimates for *operation* of FGD equipment range between \$150 and \$300 per ton of SO_2 removed. This estimate does *not* include costs associated with installation. See below for additional detail on installation costs specific to Will County 4.

d. Provide cost estimates to install FGD equipment at Will County 4.

RESPONSE: Based on the information currently available to the Agency, the capital cost of FGD equipment ranges between \$40 and \$150 per kW capacity of the unit. For Will County 4, at 598.4 MW, the cost would range between \$24 million and \$90 million. Annual operation and maintenance costs range between \$2.4 million and \$6 million.

Midwest Generation has stated in previous Board proceedings that capital costs for trona systems average around \$38 million per unit; this estimate does not include subsequent operating costs.

e. Provide cost estimates to convert Will County 4 from burning coal.

RESPONSE: The Agency has found cost estimates for the conversion of coal units to gas units to range between \$50 and \$75 per kW capacity, translating to approximately \$30 million to \$45 million for the conversion of Will County 4. However, as discussed at the third hearing, this is only for on-site work to the generating unit itself, and would not include any other costs associated with the fuel conversion, such as the cost of building infrastructure to get enough natural gas to the unit. Depending on the unit's proximity to a major fuel pipeline, these costs

could vary greatly, especially when considering the building of the infrastructure and the possible need to acquire property or leases along that path.

f. If IEPA does not have the above information, request for such information from Midwest Generation and enter it into the record.

RESPONSE: See above.

63. In response to Question 47 regarding Midwest Generation's reasoning for requesting the switch from Joliet 6 to Will County 4 for an exemption to install FGD equipment, IEPA states that "Midwest Generation is contributing a great deal of SO_2 reductions (as well as reductions in other pollutants) for the area through its overall plan to switch four units from burning coal to burning primarily natural gas...Since Midwest Generation is going far beyond FGD in making these changes, and since the company is expending more resources than anticipated in doing so, Midwest Generation requests that the exception be changed to a different unit." PC 5 at 8. Comment on whether IEPA's proposed changes to Part 217 and Part 225 could be taken up in a separate proceeding before the Board such as a rulemaking, adjusted standard, or variance proceeding.

RESPONSE: No, they could not. As explained at the third hearing in this matter, the Agency's proposed changes to Parts 217 and 225 are inextricably linked to its proposed changes to Part 214. The Agency's proposed emission limitations in Section 214.603 for Will County 3 and Joliet 6, 7, and 8, reflect the cessation of coal combustion at those units; the requirement that the units cease combusting coal, however, is in Part 225 – thus linking these Parts. Similarly, the proposed emission limitation for Will County 4 in Part 214 assumes that the unit will not be installing FGD; the exemption from FGD, however, appears in Part 225 – again linking these provisions. The revisions to Part 217 are likewise linked, as they (as well as proposed revisions to Part 225) clarify that units that no longer combust coal remain subject to the NO_X limitations in the CPS.

In short, the Agency's Part 214 proposal for these units depends upon the proposed changes to Part 225. If Part 225 were removed from this rulemaking, the Agency would need to completely reassess the corresponding provisions in Part 214; this reassessment would entail multiple rounds of additional modeling (which, as the Agency noted at the third hearing, would take weeks or even months to complete), and could result in additional sources (potentially including sources not currently part of the Agency's proposal) being required to make reductions. Further, as a practical matter, removing Parts 217 and 225 from the rule would cause considerable uncertainty for Midwest Generation regarding its obligations with respect to these units, such as the NOx limitations applicable to converted units and

converted units' obligations under the CPS. Parts 214, 217, and 225 were proposed by the Agency as a package that, at this point, cannot be feasibly bifurcated.

64. Referring to the above-quoted language, provide additional information, including quantifying emissions, regarding the collateral benefits of reductions of other pollutants through Midwest Generation's proposal to cease using coal at Joliet 6, 7, and 8 and Will County 3.

RESPONSE: As discussed at the third hearing, the Agency conservatively estimates that the conversion of the above units would result in the following annual reductions: Over 3,000 tons of NOx, over 7.5 million tons of CO_2, over 1,900 tons of particulate matter, and approximately 400 pounds of mercury. As mentioned at hearing, USEPA's Clean Power Plan was recently finalized. The CO_2 reductions referenced above may be helpful in addressing Illinois' obligations under the final rule.

65. In terms of expending resources as mentioned above, provide the following cost information:

a. Cost estimates of converting each of Joliet 6, 7, 8, and Will County 3 from burning coal.

RESPONSE: Using the same estimates for conversion as in Question 62 above, and the capacity of all four units together, the Agency estimates that the combined cost of conversions could range between $100 million and $150 million. Also, as noted above, these costs would not include pipeline infrastructure costs or costs associated with the loss of electricity sales from these units, as the converted units are only expected to operate on an intermittent basis.

Also, as discussed at the third hearing, Midwest Generation is one of only a few sources that will incur costs in complying with the Agency's proposed rule.

b. Cost estimates for installing FGD equipment on Joliet Units 7 and 8, and Will County Unit 3.

RESPONSE: Using the same estimates for installation of FGD systems as in Question 62, the Agency estimates that the combined cost to install FGD systems at all four units ranges between $80 million and $300 million, although the information provided above from Midwest Generation (see response to Question 62(d)) would suggest that the upper end of the range is likely closer to $160 million. These estimates do not include subsequent operating costs.

c. If IEPA does not have the above cost information, request for such information from Midwest Generation and enter it into the record.

RESPONSE: See above.

66. IEPA explained that with the conversion of the four Midwest Generation units and without the installation of FGD at Will County 4, "The proposed revisions, as a whole, will result in SO_2 emission reductions of more than 6,000 tons annually beginning in 2017." TSD at 11. Table 4 of the TSD shows calculated emissions in tons per year with and without the proposed amendments based on the CPS SO_2 rate. Assuming Will County 4 installed FGD and Will County 3 and Joliet Units 6, 7, and 8 did not cease burning coal, respond to the following:

a. Identify the allowable emission rates for each unit in terms of lb/hr for the purposes of demonstrating attainment.

RESPONSE: To properly address this question and determine the "allowable emission rates" that would demonstrate attainment, supplemental modeling would need to be conducted. Present time constraints for completing any such modeling, especially with multiple iterations, prevent a definitive determination. In lieu of such modeling, and despite significant shortcomings, the Agency has made best estimates of "allowable emission rates" based upon modeling results previously generated. The estimated emission rates (and percentage reductions from current hourly allowable emission rates) are as follows: Will County 3: 2,838 lbs/hour (42% reduction); Will County 4: 3,783 lbs/hour (58% reduction); Joliet 6: 5,019 lbs/hour (21% reduction); Joliet 7: 7,353 lbs/hour (32% reduction); Joliet 8: 7,368 lbs/hour (36% reduction).

b. Quantify the SO_2 reductions for each of these units in terms of tons per year beginning in 2017 and compare it to the 6,000 tons referenced above.

RESPONSE: The Agency's analysis shows that there would be <u>no</u> overall SO_2 emission reductions beyond current CPS requirements – as such, the Agency's proposal would result in the full 6,000 tons of reductions compared to using the hypothetical method discussed above.

To clarify, the reduction of 6,000 tons referenced in the TSD is the difference between annual emissions estimates of the entire Midwest Generation fleet under the requirements of the CPS when compared to estimates of emissions of the entire Midwest Generation fleet under the proposed amendments. The emission estimates for the CPS scenario reflect a 0.15 lb/mmBtu limit applied to the heat input of all units in the CPS group, as the CPS does not contain unit-specific limits.

The estimated lb/hr emission rates described in response to Question 66(a) above would actually be much *less* stringent on an annual basis than the rates set forth in the CPS or the Agency's proposed revisions. Using these hourly limits to calculate allowable annual emissions would result in annual emissions from each unit that exceed the amounts allowed under the current CPS requirements. For instance, for Will County 3, calculating an annual emission estimate from the above maximum hourly limit of 2,838 lb/hr would result in an estimated 12,430 tons of SO_2 emitted per year. This alone would be greater than the amount that Midwest Generation's

entire fleet is expected to emit under the proposed amendments (and the Agency's estimate in Table 4 included emissions from all five units under discussion, as well as the units at Powerton and Waukegan).

Additionally, while Will County 4's hypothetical hourly maximum emission rate discussed in the Agency's response to Question 66(a) above may be more stringent than the limit set forth in the Agency's current proposal, the CPS only requires compliance with an overall fleet-wide average. Therefore, a lower hourly emission limit at one unit does not necessarily lead to reductions fleet-wide for the purpose of comparing the hypothetical emission limits above to the CPS estimates in the TSD. This comparison highlights the difference between the fleet-wide annual mass SO_2 emission rate set forth in the CPS, and the hourly limits in Part 214 that would be necessary to demonstrate attainment of the NAAQS.

Finally, the Agency notes that under the current CPS, Will County 4 is not required to install FGD until the end of 2018. Under the Agency's proposal, however, Will County 3 and the Joliet units would be required to cease combustion of coal by the beginning of 2017.

67. IEPA's proposed language at 35 Ill. Adm. Code 225.296(b) provides:

> Other Control Technology Requirements for SO_2. On and after April16, 2015, Will County 3 must not combust coal. On and after December 31, 2016, Joliet 6, 7, and 8 must not combust coal. Owners or operators of the other specified EGUs must either permanently shut down, permanently cease combusting coal at, or install FGD equipment on each specified EGU (except Will County 4~~Joliet 5~~), on or before December 31, 2018, unless an earlier date is specified in subsection (a) of this Section.

a. Address whether the proposed revisions to this section are necessary for making the attainment demonstration for the one-hour SO_2 NAAQS or if the limitations in proposed 35 Ill. Adm. Code Part 214 are sufficient.

RESPONSE: The proposed limits in Part 214 for Will County 3 and 4 and Joliet 6, 7, and 8 reflect the proposed revisions to Part 225 above; these limits are necessary to demonstrate attainment of the 1-hour SO_2 NAAQS. So, as noted previously, these proposed revisions to Section 225.296(b) are inextricably linked to the proposed limits in Part 214, and thus to making the attainment demonstration for the one-hour SO_2 NAAQS.

b. In particular, if Will County 4 does not receive the FGD exemption, address whether fuel conversions at the other facilities are necessary to demonstrate attainment.

RESPONSE: The Agency cannot say with any certainty whether conversions of Will County 3 and Joliet 6, 7, and 8 would be necessary, but the units would definitely need some sort of control, and, as previously noted, other units not owned and operated by Midwest Generation may need additional controls as well. The Agency cannot determine exactly how much control would be needed, as it has not modeled those scenarios and does not have sufficient time at this point to do so. As explained at the third hearing, every scenario that the Agency models takes approximately one week of time for the Agency computers to process. The Agency has not modeled the scenarios described by the Board above, as modeling every possible alternate scenario was not only infeasible, but also unnecessary from the standpoint of demonstrating attainment of the NAAQS.

c. Comment on the Board amending the proposal at second notice to not propose the change in the parenthetical in this section. In other words, comment on the Board not making the following change: "(except Will County 4~~Joliet 5~~)."

RESPONSE: The Agency strongly opposes such a change. The proposed amendments will result in a reduction of SO_2 emissions of between 30-35% overall at the Will County facility. This reduction at that facility along with the reductions at the other EGUs impacting the Lemont NAA (greater than 99% reductions at the converted Joliet units) are adequate to demonstrate attainment and provide significant air quality benefits in Illinois.

d. Address whether the emission limitations in proposed Section 214.603 would need to be revised if Will County 3 and Joliet 6, 7, and 8 did not cease burning coal and Will County 4 installed FGD.

RESPONSE: Yes. The emission limitations in proposed Section 214.603 reflect the interplay of modeled impacts for all modeled sources. These would need to be revised if modeled impacts change as a result of modeled emissions being changed.

As noted at the third hearing, a change of this sort would involve a new set of multi-iteration modeling – taking weeks or even months to complete – that would not impact Midwest Generation alone. As previously discussed, the Agency's process involved examining which sources were impacting each nonattainment receptor in order to bring it into attainment. It may be that other sources had an equal or greater impact on some nonattainment receptor in the model as compared to Will County 3 or Joliet 6, 7, and 8, but because of the voluntary efforts that Midwest Generation proposed taking, the Agency never had to examine potential reductions from those sources. If the Agency were to go back now and suggest that Midwest Generation not make these conversions, the full process of modeling would need to

begin anew, through the full set of iterations, to see if some other company that has not even been brought into these proceedings might be impacted and might need to make a reduction to offset the reductions that Midwest Generation offered. This would not only significantly delay the process of demonstrating attainment, but would potentially be unfair to any source that would need to be brought in for reductions at this late date.

68. During the first hearing, a public comment indicated that the basis for the FGD exemption in 35 Ill. Adm. Code 225.296(b) for Joliet 5 was that the unit had a shorter life span than other units in the fleet. 7-8-15 Tr. at 53. What is the life span of Joliet 5, now known as Joliet 6, and how does it compare to the life span of Will County 4, assuming both units burn coal?

RESPONSE: There has been no evidence provided in this proceeding to support the claim that the basis of the Joliet FGD exemption was due to the unit's shorter life span, and <u>none</u> of the Agency personnel who worked on the CPS rule has any recollection that this was the case. Furthermore, the CPS addressed units that were known to be shutting down by requiring such shutdowns by specified dates; Joliet 6 was *not* included among these units. The CPS does not require that Joliet 6 shut down and therefore, from a regulatory standpoint, its "life span" under the CPS is indefinite. The same analysis applies to Will County 4.

With this in mind, the Agency cannot opine on the life span of any given unit. How long a source chooses to keep a unit operating depends on multiple economic factors, which may change over time (for example, when a unit converts to a different fuel). The Agency understands that economic considerations are periodically evaluated, but that the actual life of a unit is not dependent on, or determined by, the depreciation of a unit for accounting purposes. The Agency further understands that both Joliet 6 and Will County 4 began operation within four years of one another, so the life span would not be expected to be significantly different.

69. Comments during the hearings indicated that environmental groups were not included in development of IEPA's proposed revisions at Section 225.296(b) based on Midwest Generation's proposal to convert Joliet 6, 7, and 8 and Will County 3 and exempt Will County 4 from the requirement to install FGD. 7-8-15 Tr. at 54, 7-29-15 Tr. at 85, 100-101, 116. During IEPA's outreach efforts, explain whether IEPA discussed Midwest Generation's proposal with environmental groups or other stakeholders.

RESPONSE: Yes, the Agency provided environmental groups and other stakeholders a draft of its proposal, including the proposed amendments to Parts 214, 217, and 225, for comment prior to submittal to the Board. David Bloomberg sent the draft modifications via an e-mail on February 18 to representatives from environmental groups, industry groups, and specific impacted companies. At least five recipients on that e-mail were from environmental organizations. The Sierra Club and Environmental Law and Policy Center ("ELPC") submitted comments on

March 9. Those comments addressed two areas where there remains disagreement today (the Powerton 30-day average and the substitution of Will County 4 for Joliet 6 regarding the FGD exemption) as well as two areas where there appeared to be confusion or misconceptions on the part of the commenters (a comment about grid spacing at a fenceline and one about RACT/RACM). The Agency and Sierra Club/ELPC subsequently held several conference calls to discuss the issues and to address any misconceptions evidenced in the comments.

At the third hearing, Board Member Zalewski asked whether the Agency had made any changes to the proposed rule based upon comments from the environmental groups after they reviewed the draft. Since the comments submitted by the Sierra Club/ELPC only addressed the items described above, the Agency did not make changes to the proposed rule. The Sierra Club/ELPC disagreed – and continues to disagree – with the 30-day average for Powerton despite the fact that USEPA has approved the average. The Sierra Club/ELPC also disagreed – and continues to disagree – with moving the FGD exemption from Joliet 6 to Will County 4 despite the demonstrated overall environmental benefit from Midwest Generation's plan to cease use of coal at Joliet 6, 7, and 8, and Will County 3. The other two issues, as noted above, were misunderstandings on the part of the Sierra Club/ELPC. As such, no changes in the rules were warranted, though the Agency did its best to explain these issues to Sierra Club/ELPC and attempt to ensure its Statement of Reasons and other documents better explained these matters as well.

ILLINOIS ENVIRONMENTAL
PROTECTION AGENCY

By: /s/ Dana Vetterhoffer
Assistant Counsel

DATED: August 14, 2015
1021 N. Grand Ave. East
P.O. Box 19276
Springfield, IL 62794-9276
(217) 782-5544

BEFORE THE ILLINOIS POLLUTION CONTROL BOARD

IN THE MATTER OF:	)	
	)	R15-21
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217, NITROGEN OXIDES EMISSIONS,	)	
AND PART 225, CONTROL OF EMISSIONS	)	
FROM LARGE COMBUSTION SOURCES	)	

CERTIFICATE OF SERVICE

I, the undersigned, an attorney, affirm that I have served the attached Illinois Environmental Protection Agency's Responses to the Board's Third Set of Questions upon the following person(s) by e-mailing it to the e-mail address(es) indicated below:

Daniel Robertson, Hearing Officer
Illinois Pollution Control Board
daniel.robertson@illinois.gov

I affirm that my e-mail address is dana.vetterhoffer@illinois.gov; the number of pages in the e-mail transmission is 80; and the e-mail transmission took place today before 5:00 p.m.

I also affirm that I am mailing the attached by first-class mail from Springfield, Illinois, with sufficient postage affixed, to the following persons:

SEE ATTACHED SERVICE LIST

ILLINOIS ENVIRONMENTAL
PROTECTION AGENCY

By: /s/ Dana Vetterhoffer
Assistant Counsel

DATED: August 14, 2015

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TITLE 35: ENVIRONMENTAL PROTECTION
SUBTITLE B: AIR POLLUTION
CHAPTER I: POLLUTION CONTROL BOARD
SUBCHAPTER c: EMISSION STANDARDS AND LIMITATIONS FOR STATIONARY SOURCES

PART 214
SULFUR LIMITATIONS

SUBPART A: GENERAL PROVISIONS

SUBPART B: NEW FUEL COMBUSTION EMISSION SOURCES

SUBPART C: EXISTING SOLID FUEL COMBUSTION EMISSION SOURCES

SUBPART D: EXISTING LIQUID OR MIXED FUEL COMBUSTION EMISSION SOURCES

SUBPART E: AGGREGATION OF SOURCES OUTSIDE METROPOLITAN AREAS

SUBPART V: ELECTRIC POWER PLANTS

SUBPART X: UTILITIES

SUBPART AA: REQUIREMENTS FOR CERTAIN SO_2 SOURCES

AUTHORITY: Implementing Section 10 and authorized by Section 27 of the Environmental Protection Act [415 ILCS 5/10 and 27].

SOURCE: Adopted as Chapter 2: Air Pollution, Rule 204: Sulfur Emission Standards and Limitations, R71-23, 4 PCB 191, filed and effective April 14, 1972; amended in R74-2 and R75-5, 32 PCB 295, at 3 Ill. Reg. 5, p. 777, effective February 3, 1979; amended in R74-2, R75-5, 38 PCB 129, at 4 Ill. Reg. 28, p. 417, effective June 26, 1980; amended in R78-17, 40 PCB 291, at 5 Ill. Reg. 1892, effective February 17, 1981; amended in R77-15, 44 PCB 267, at 6 Ill. Reg. 2146, effective January 28, 1982; amended and renumbered in R80-22(A), at 7 Ill. Reg. 4220, effective March 28, 1983; codified 7 Ill. Reg. 13579; amended in R80-22(B), at 8 Ill. Reg. 6172, effective April 24, 1984; amended in R84-28, at 10 Ill. Reg. 9806, effective May 20, 1986; amended in R86-31, at 12 Ill. Reg. 17387, effective October 14, 1988; amended in R86-30, at 12 Ill. Reg. 20778, effective December 5, 1988; amended in R87-31 at 15 Ill. Reg. 1017, effective January 15, 1991; amended in R02-21 at 27 Ill. Reg. 12101, effective July 11, 2003; amended in R04-12/20 at 30 Ill. Reg. 9671, effective May 15, 2006.

SUBPART A: GENERAL PROVISIONS

Section 214.101 Measurement Methods

A determination of non-compliance based on any subsection of this Section shall not be refuted by evidence of compliance with any other subsection.

a) Sulfur Dioxide Measurement. Measurement of sulfur dioxide emissions from stationary sources shall be made according to an applicable method specified in 40 CFR 60, Appendix A, Method 6, 6A, 6B, or 6C, incorporated by reference in Section 214.104(a), or by measurement procedures established pursuant to 40 CFR 60.8(b), incorporated by reference in Section 214.104(b), or by an installed certified continuous emissions monitoring system, or by an alternative monitoring method available under 40 CFR 75, incorporated by reference in Section 214.104(e). ~~(Ill. Rev. Stat. 1989, ch. 111 1/2, par. 1010.)~~

b) Sulfuric Acid Mist and Sulfur Trioxide Measurement. Measurement of sulfuric acid mist and sulfur trioxide shall be according to the barium-thorin titration method specified in 40 CFR 60, Appendix A, Method 8, incorporated by reference in Section 214.104(a), or a controlled condensate method approved in writing by the Agency.

c) Solid Fuel Averaging Measurement Daily Analysis Method. This subsection applies to sources at plants with total solid fuel-fired heat input capacity exceeding 439.5 MW (1500 ~~million~~ mmBtu/hr). If daily fuel analysis is used to demonstrate compliance or non-compliance with Sections 214.122, 214.141, 214.142(a) 214.162, 214.186 and 214.421, the sulfur dioxide emission rate to be compared to the emission limit shall be considered to be the result of averaging daily samples taken over any consecutive two-month period provided no more than 5 percent of the sample values are greater than 20 percent above the sample average. If samples from a source cannot meet this statistical criterion, each individual daily sample analysis for such source shall be compared to the source's emission limit to determine compliance. The specific ASTM procedures, incorporated by reference in Section 214.104(c), shall be used for solid fuel sampling, sulfur, and heating value determinations.

de) Weekly Analysis Method. This subsection applies to sources at plants with total solid fuel-fired heat input capacity exceeding 146.5 MW (500 ~~million~~ mmBtu/hr) but not exceeding 439.5 MW (1500 ~~million~~ mmBtu/hr). These plants shall demonstrate compliance or non-compliance with Sections 214.122, 214.141, 214.142(a), 214.162, 214.186 and 214.421 by either an analysis of calendar weekly composites of daily fuel samples or by compliance with subsection (c) above, at the option of the plant. The specific ASTM procedures incorporated by reference in Section 214.104(c), shall be used for sulfur and heating value determinations.

e) Monthly Analysis Method. This subsection applies to sources at plants with total fuel-fired heat input capacity exceeding 14.65 MW (50 ~~millions~~ mmBtu/hr) but not exceeding 146.5 MW (500 ~~million~~ mmBtu/hr). These plants shall demonstrate compliance or non-compliance with Sections 214.122, 214.141, 214.142(a), 214.162, 214.186 and 214.421 by either an analysis of calendar monthly composites of daily fuel samples or by compliance with subsection (c) above, at the option of the plant. ASTM procedures incorporated by reference in Section 214.104(c), shall be used for sulfur and heating value determinations.

f) Small Source Alternative Method. This subsection applies to sources at plants with total solid fuel-fired heat input capacity not exceeding 14.65 MW (50 ~~million~~ mmBtu/hr). Compliance or non-compliance with Sections 214.122, 214.141, 214.142(a), 214.162, 214.186 and 214.421 shall be demonstrated by a calendar month average sulfur dioxide emission rate.

g) Exemptions. Subsections (c) through (f) shall not apply to sources controlling sulfur dioxide emissions by flue gas desulfurization equipment or by sorbent injection.

h) Hydrogen Sulfide Measurement. For purposes of determining compliance with Section 214.382(c), the concentration of hydrogen sulfide in petroleum refinery fuel gas shall be measured using the Tutwiler Procedure specified in 40 CFR 60.648, incorporated by reference in Section 214.104(d).

(Source: Amended at 39 Ill. Reg. , effective)

Section 214.102 Abbreviations and Units

a) The following abbreviations are used in this Part:

Btu or btu	British thermal units ~~(60 F)~~
ft	foot
gr	grains
J	Joule
kg	kilogram

kg/MW-hr	kilograms per megawatt-hour
km	kilometer
lbs	pounds
lbs/mmB~~b~~tu	pounds per million B~~b~~tu
m	meter
mg	milligram
Mg	megagram, metric ton or tonne
mi	mile
mmB~~b~~tu	million British thermal units
mmB~~b~~tu/hr	million British thermal units per hour
MW	megawatt; one million watts
MW-hr	megawatt-hour
ng	nanogram, one billionth of a gram ~~by volume~~
ng/J	nanograms per Joule
ppm	parts per million
scf	standard cubic foot
scm	standard cubic meter
T	English ton

b) The following conversion factors have been used in this Part:

English	Metric
2.205 lb	1 kg
1 T	0.907 Mg
1 lb/T	0.500 kg/Mg
mmB~~b~~tu/hr	0.293 MW
1 lb/mmB~~b~~tu	1.548 kg/MW-hr
1 mi	1.61 km
1 gr/scf	2289 mg/scm

(Source: Amended at 39 Ill. Reg. , effective)

Section 214.103 Definitions

Unless otherwise indicated, the~~The~~ definitions of 35 Ill. Adm. Code 201 and 211 apply to this Part.

(Source: Amended at 39 Ill. Reg. , effective)

Section 214.104 Incorporations by Reference

The following materials are incorporated by reference. These incorporations do not include any later amendments or editions.

a) 40 CFR 60, Appendix A (2014~~1989~~):

1) Method 1: Sample and Velocity Traverses for Stationary Sources;

2) Method 2: Determination of Stack Gas Velocity and Volumetric Flow Rate;

3) Method 3: Gas Analysis for the Determination of Dry Molecular Weight;

4) Method 4: Determination of Moisture Content in Stack Gases;

5~~1~~) Method 6: Determination of Sulfur Dioxide Emissions From Stationary Sources;

6~~2~~) Method 6A: Determination of Sulfur Dioxide, Moisture, and Carbon Dioxide Emissions From Fossil Fuel Combustion Sources;

7~~3~~) Method 6B: Determination of Sulfur Dioxide and Carbon Dioxide Daily Average Emissions From Fossil Fuel Combustion Sources;

8~~4~~) Method 6C: Determination of Sulfur Dioxide Emissions From Stationary Sources (Instrumental Analyzer Procedure);

9~~5~~) Method 8: Determination of Sulfuric Acid Mist and Sulfur Dioxide Emissions From Stationary Sources;~~.~~

10) Method 19: Determination of Sulfur Dioxide Removal Efficiency and Particulate Matter, Sulfur Dioxide, and Nitrogen Oxide Emission Rates.

b) 40 CFR 60.8(b) (2014~~1989~~), Performance Tests.

c) American Society for Testing and Materials, 1916 Race Street, Philadelphia, PA 19103:

1) For solid fuel sampling:
ASTM D-2234 (1989)
ASTM D-2013 (1986)

2) For sulfur determinations:
ASTM D-3177 (1984)
ASTM D-2622 (1987)
ASTM D-3180 (1984)
ASTM D-4239 (1985)

3) For heating value determinations:
ASTM D-2015 (1985)
ASTM D-3286 (1985)

d) Tutwiler Procedure for hydrogen sulfide, 40 CFR 60.648 (2014~~1989~~).

e) 40 CFR 75 (2014).

f) USEPA's Emission Measurement Center Guideline Document (GD-042), Preparation and Review of Site-Specific Emission Test Plans, Revised March 1999.

(Source: Amended at 39 Ill. Reg. , effective)

SUBPART B: NEW FUEL COMBUSTION EMISSION SOURCES

Section 214.121 Large Sources

This section applies to new fuel combustion emission sources with actual heat input greater than 73.2 MW (250 mmB~~b~~tu/hr).

a) Solid Fuel Burned Exclusively. No person shall cause or allow the emission of sulfur dioxide into the atmosphere in any one hour period from any new fuel combustion emission source greater than 73.2 MW (250 mmB~~b~~tu/hr), burning solid fuel exclusively, to exceed 1.86 kg of sulfur dioxide per MW-hr of actual heat input (1.2 lbs/mmB~~b~~tu). (Board Note: This section was invalidated in Commonwealth Edison v. PCB, 25 Ill. App. 3d 271, 62 Ill.2d 494, 43 N.E.2d 459, 323 N.E. 2d 84, Ashland Chemical Corp. v. PCB, 64 Ill. App.3d 169, and Illinois State Chamber of Commerce v. PCB, 67 Ill. App.3d 839, 384 N.E.2d 922, 78 Ill.2d 1, 398 N.E.2d 9.)

b) Liquid Fuel Burned Exclusively.

<u>1) Prior to January 1, 2017, no</u>~~No~~ person shall cause or allow the emission of sulfur dioxide into the atmosphere in any one hour period from any new fuel combustion emission source <u>with actual heat input</u> greater than 73.2 MW (250 mm<u>B</u>~~b~~tu/hr), burning liquid fuel exclusively<u>, to exceed the following</u>:

<u>A</u>~~1~~) ~~To exceed~~ 1.2 kg of sulfur dioxide per MW-hr of actual heat input when residual fuel oil is burned (0.8 lbs/mm<u>B</u>~~b~~tu); and

<u>B</u>~~2~~) ~~To exceed~~ 0.46 kg of sulfur dioxide per MW-hr of actual heat input when distillate fuel oil is burned (0.3 lbs/mm<u>B</u>~~b~~tu)<u>;</u>~~.~~

<u>2) On and after January 1, 2017, the owner or operator of a new fuel combustion emission source with actual heat input greater than 73.2 MW (250 mmBtu/hr), burning liquid fuel exclusively, must comply with the following:</u>

<u>A) The sulfur content of all residual fuel oil used by the fuel combustion emission source must not exceed 1000 ppm;</u>

<u>B) The sulfur content of all distillate fuel oil used by the fuel combustion emission source must not exceed 15 ppm; and</u>

<u>C) The owner or operator must:</u>

<u>i) Maintain records demonstrating that the fuel oil used by the fuel combustion emission source complies with the requirements in subsections (b)(2)(A) and (b)(2)(B) of this Section, such as records from the fuel supplier indicating the sulfur content of the fuel oil;</u>

<u>ii) Retain the records for at least 5 years, and provide copies of the records to the Agency within 30 days of receipt of a request by the Agency; and</u>

<u>iii) Notify the Agency within 30 days after discovery of deviations from any of the requirements in this subsection (b)(2). At minimum, and in addition to any permitting obligations, such notification must</u>

include a description of the deviations, a discussion of the possible cause of the deviations, any corrective actions taken, and any preventative measures taken.

(Source: Amended at 39 Ill. Reg. , effective)

Section 214.122 Small Sources

This section applies to new fuel combustion emission sources with actual heat input smaller than, or equal to, 73.2 MW (250 mmB~~b~~tu/hr).

a) Solid Fuel Burned Exclusively. No person shall cause or allow the emission of sulfur dioxide into the atmosphere in any one hour period from any new fuel combustion source with actual heat input smaller than, or equal to, 73.2 MW (250 mmB~~b~~tu/hr), burning solid fuel exclusively, to exceed 2.79 kg of sulfur dioxide per MW-hr of actual heat input (1.8 lbs/mmB~~b~~tu).

b) Liquid Fuel Burned Exclusively.

1) Prior to January 1, 2017, no~~No~~ person shall cause or allow the emission of sulfur dioxide into the atmosphere in any one hour period from any new fuel combustion emission source with actual heat input smaller than, or equal to, 73.2 MW (250 mmB~~b~~tu/hr), burning liquid fuel exclusively, to exceed the following:

A~~1~~) ~~To exceed~~ 1.55 kg of sulfur dioxide per MW-hr of actual heat input when residential fuel oil is burned (1.0 lbs/mmB~~b~~tu); and

B~~2~~) ~~To exceed~~ 0.46 kg of sulfur dioxide per MW-hr of actual heat input when distillate fuel oil is burned (0.3 lbs/mmB~~b~~tu);~~.~~

2) On and after January 1, 2017, the owner or operator of a new fuel combustion emission source with actual heat input smaller than, or equal to, 73.2 MW (250 mmBtu/hr), burning liquid fuel exclusively, must comply with the following:

A) The sulfur content of all residual fuel oil used by the fuel combustion emission source must not exceed 1000 ppm;

B) The sulfur content of all distillate fuel oil used by the fuel combustion emission source must not exceed 15 ppm; and

C) The owner or operator must:

i) Maintain records demonstrating that the fuel oil used by the fuel combustion emission source complies with the requirements in subsections (b)(2)(A) and (b)(2)(B) of this Section, such as records from the fuel supplier indicating the sulfur content of the fuel oil;

ii) Retain the records for at least 5 years, and provide copies of the records to the Agency within 30 days of receipt of a request by the Agency; and

iii) Notify the Agency within 30 days after discovery of deviations from any of the requirements in this subsection (b)(2). At minimum, and in addition to any permitting obligations, such notification must include a description of the deviations, a discussion of the possible cause of the deviations, any corrective actions taken, and any preventative measures taken.

(Source: Amended at 39 Ill. Reg. , effective)

SUBPART D: EXISTING LIQUID OR MIXED FUEL COMBUSTION EMISSION SOURCES

Section 214.161 Liquid Fuel Burned Exclusively

a) Prior to January 1, 2017, no~~No~~ person shall cause or allow the emission of sulfur dioxide into the atmosphere in any one hour period from any existing fuel combustion emission source, burning liquid fuel exclusively, to exceed the following:

1~~a~~) ~~To exceed~~ 1.55 kg of sulfur dioxide per MW-hr of actual heat input when residual fuel oil is burned (1.0 lbs/mmB~~b~~tu); and

2~~b~~) ~~To exceed~~ 0.46 kg of sulfur dioxide per MW-hr of actual heat input when distillate fuel oil is burned (0.3 lbs/mmB~~b~~tu).

b) Except as provided in subsections (c) and (d) of this Section, on and after January 1, 2017, the owner or operator of an existing fuel combustion emission source, burning liquid fuel exclusively, must comply with the following:

1) The sulfur content of all residual fuel oil used by the fuel combustion emission source must not exceed 1000 ppm;

2) The sulfur content of all distillate fuel oil used by the fuel combustion emission source must not exceed 15 ppm; and

3) The owner or operator must:

A) Maintain records demonstrating that the fuel oil used by the fuel combustion emission source complies with the requirements in subsections (b)(1) and (b)(2) of this Section, such as records from the fuel supplier indicating the sulfur content of the fuel oil;

B) Retain the records for at least 5 years, and provide copies of the records to the Agency within 30 days of receipt of a request by the Agency; and

C) Notify the Agency within 30 days after discovery of deviations from any of the requirements in this subsection (b). At minimum, and in addition to any permitting obligations, such notification must include a description of the deviations, a discussion of the possible cause of the deviations, any corrective actions taken, and any preventative measures taken.

c) The sulfur content limitation for distillate fuel oil in subsection (b)(2) of this Section does not apply to existing electric generating units at Midwest Generation's Joliet station (located at or near 1800 Channahon Road, Joliet, IL), Powerton station (located at or near 13082 E. Manito Road, Pekin, IL), Waukegan station (located at or near 401 East Greenwood Avenue, Waukegan, IL), and Will County station (located at or near 529 East 135th, Romeoville, IL). The owner or operator of such electric generating units must instead comply with the following:

1) From January 1, 2016, through December 31, 2018, the sulfur content of all distillate fuel oil purchased for use by such electric generating units must not exceed 15 ppm;

2) From January 1, 2017, through December 31, 2018, the sulfur content of all distillate fuel oil used by such electric generating units must not exceed 500 ppm;

3) On and after January 1, 2019, the sulfur content of all distillate fuel oil used by such electric generating units must not exceed 15 ppm;

4) The owner or operator must:

A) Maintain records demonstrating that the distillate fuel oil purchased from January 1, 2016, through December 31, 2018, for use by the electric generating units complies with the requirements in subsection (c)(1) of this Section, such as records from the fuel supplier indicating the sulfur content of the fuel oil, and maintain records indicating the date of purchase of the fuel oil;

B) Maintain records demonstrating that the distillate fuel oil used from January 1, 2017, through December 31, 2018, by the electric generating units complies with the requirements in subsection (c)(2) of this Section, such as records from the fuel supplier indicating the sulfur content of the fuel oil;

C) On and after January 1, 2019, maintain records demonstrating that the distillate fuel oil used by the electric generating units complies with the requirements in subsection (c)(3) of this Section, such as records from the fuel supplier indicating the sulfur content of the fuel oil;

D) Retain all records required by this subsection (c) for at least 5 years, and provide copies of the records to the Agency within 30 days of receipt of a request by the Agency; and

E) Notify the Agency within 30 days after discovery of deviations from any of the requirements in this subsection (c). At minimum, and in addition to any permitting obligations, such notification must include a description of the deviations, a discussion of the possible cause of the deviations, any corrective actions taken, and any preventative measures taken.

d) The sulfur content limitation for distillate fuel oil in subsection (b)(2) of this Section does not apply to existing fuel combustion emission sources at Caterpillar's Montgomery facility (located at or near 325 South Route 31, Montgomery, IL). The owner or operator of such fuel combustion emission sources must instead comply with the following:

1) On and after January 1, 2016:

A) The sulfur content of all distillate fuel oil purchased for use by the fuel combustion emission sources must not exceed 15 ppm; and

B) The sulfur content of all distillate fuel oil used by the fuel combustion emission sources must not exceed 500 ppm;

2) The owner or operator must:

A) Maintain records demonstrating that the distillate fuel oil purchased on and after January 1, 2016, for use by the fuel combustion emission sources complies with the requirements in subsection (d)(1)(A) of this Section, such as records from the fuel supplier indicating the sulfur content of the fuel oil, and maintain records indicating the date of purchase of the fuel oil;

B) Maintain records demonstrating that the distillate fuel oil used on and after January 1, 2016, by the fuel combustion emission sources complies with the requirements in subsection (d)(1)(B) of this Section, such as records from the fuel supplier indicating the sulfur content of the fuel oil;

C) Retain all records required by this subsection (d) for at least 5 years, and provide copies of the records to the Agency within 30 days of receipt of a request by the Agency; and

D) Notify the Agency within 30 days after discovery of deviations from any of the requirements in this subsection (d). At minimum, and in addition to any permitting obligations, such notification must include a description of the deviations, a discussion of the possible cause of the deviations, any corrective actions taken, and any preventative measures taken.

(Source: Amended at 39 Ill. Reg. , effective)

Section 214.162 Combination of Fuels

a) No person shall cause or allow the emission of sulfur dioxide into the atmosphere in any one hour period from any fuel combustion emission source burning simultaneously any combination of solid, liquid and gaseous fuels to exceed the allowable emission rate determined by the following equation:

$$E = S_S H_S + S_d H_d + S_R H_R$$

b) Symbols in the equation mean the following:

E = allowable sulfur dioxide emission rate;

S_S = solid fuel sulfur dioxide emission standard which is applicable;

S_d = distillate oil sulfur dioxide emission standard determined from the table in subsection (d);

S_R = residual fuel oil sulfur dioxide emission standard which is applicable;

H_S = actual heat input from solid fuel;

H_d = actual heat input from distillate fuel oil;

H_R = actual heat input from residual fuel oil;

c) That portion of the actual heat input that is derived:

1) From the burning of gaseous fuels produced by the gasification of solid fuels shall be included in H_S;

2) From the burning of gaseous fuels produced by the gasification of distillate fuel oil shall be included in H_d;

3) From the burning of gaseous fuels produced by the gasification of residual fuel oil shall be included in H_R;

4) From the burning of gaseous fuels produced by the gasification of any other liquid fuel shall be included in H_R; and,

5) From the burning of by-product gases such as those produced from a blast furnace or a catalyst regeneration unit in a petroleum refinery shall be included in H_R.

d) Metric or English units may be used in the equation of subsection (a) as follows:

Parameter	Metric	English
E	kg/hr	lbs/hr
S_S, S_R	kg/MW-hr	lbs/mm<u>B</u>~~b~~tu
S_d <u>prior to January 1, 2017</u>	0.46 kg/MW-hr	0.3 lbs/mm<u>B</u>~~b~~tu
<u>S_d on and after January 1, 2017</u>	<u>0.0023 kg/MW-hr</u>	<u>0.0015 lb/mmBtu</u>
H_S, H_d, H_R	MW	mm<u>B</u>~~b~~tu/hr

(Source: Amended at 39 Ill. Reg. , effective)

SUBPART F: ALTERNATIVE STANDARDS FOR SOURCES INSIDE METROPOLITAN AREAS

Section 214.201 Alternative Standards for Sources in Metropolitan Areas

Any owner or operator of an existing fuel combustion emission source located in the Chicago, St. Louis (Illinois) or Peoria major metropolitan areas may petition the Board for approval of an alternate emission rate specified in emissions of pounds of sulfur dioxide per mm<u>B</u>~~b~~tu of actual heat input for any such fuel combustion emission source, up to a maximum or 6.8 pounds of sulfur dioxide per mm<u>B</u>~~b~~tu of actual heat input (10.5 kg/MW-hr). Such person shall prove in an adjudicative hearing before the Board that the proposed emission rate will not, under predictable worst case conditions cause or contribute to a violation of any applicable primary or secondary sulfur dioxide ambient air quality standard or of any applicable prevention of significant deterioration increment. An emission rate approved pursuant to this Section shall be a substitute for that standard otherwise required by this Part. <u>Nothing in this Section, however, excuses a source subject to Subpart AA of this Part from complying with the requirements set forth in such Subpart.</u>

a) Every owner or operator of an existing fuel combustion emission source so petitioning the Board for approval of an emission standard shall follow the applicable procedures described in 35 Ill. Adm. Code, Subtitle A, Chapter I.

b) Any emission standard so approved shall be included as a condition in operating permits issued pursuant to 35 Ill. Adm. Code 201. Any owner or operator of a fuel combustion emission source who receives Board approval of such an emission standard shall apply to the Agency within 30 days of approval of such standard for a revision of its operating permit for such source.

c) No owner or operator of an existing fuel combustion emission source shall seek ~~such~~ an alternate emission rate under this Section,~~exemption~~ or comply with an alternate emission rate granted under this Section,~~the emission standard so granted~~ by the use of dispersion enhancement techniques referred to in Section 214.202.

(Source: Amended at 39 Ill. Reg. , effective)

SUBPART K: PROCESS EMISSION SOURCES

Section 214.300 Scope

Subpart K contains general rules for sulfur emissions from process sources. These may be modified by industry and site specific rules in other Subparts of this Part~~N et seq~~. Subpart K also contains sulfur content limitations for fuel oil used by process emission sources. These sulfur content limitations apply regardless of industry and site specific rules set forth in other Subparts of this Part.

(Source: Amended at 39 Ill. Reg. , effective)

Section 214.305 Fuel Sulfur Content Limitations

a) Except as provided in subsections (b), (c), and (d) of this Section, on and after January 1, 2017, the owner or operator of a process emission source must comply with the following:

1) The sulfur content of all residual fuel oil used by the process emission source must not exceed 1000 ppm;

2) The sulfur content of all distillate fuel oil used by the process emission source must not exceed 15 ppm; and

3) The owner or operator must:

A) Maintain records demonstrating that the fuel oil used by the process emission source complies with the requirements in subsections (a)(1) and (a)(2) of this Section, such as records from the fuel supplier indicating the sulfur content of the fuel oil;

B) Retain the records for at least 5 years, and provide copies of the records to the Agency within 30 days of receipt of a request by the Agency; and

C) Notify the Agency within 30 days after discovery of deviations from any of the requirements in this subsection (a). At minimum, and in addition to any permitting obligations, such notification must include a description of the deviations, a discussion of the possible cause of the deviations, any corrective actions taken, and any preventative measures taken.

b) The sulfur content limitation for distillate fuel oil in subsection (a)(2) of this Section does not apply to distillate fuel oil used by "TC-F/TC-L/TCL Wing 5" and "TC-F/TC-L Alternative" at Caterpillar Inc. Technical Center (located at or near 1311 East Cedar Hills Dr., Mossville, IL) for purposes of research and development or testing of equipment intended for sale outside of Illinois. This exemption is limited to a combined total of 150,000 gallons of distillate fuel oil per calendar year. The sulfur content of such fuel oil must not exceed 500 ppm. The owner or operator of the process emission sources described above must also comply with the following:

1) Maintain records indicating the amount of distillate fuel oil used by the process emission sources each calendar year for purposes of research and development or testing of equipment for sale outside of Illinois, as well as records demonstrating that such fuel oil complies with the requirements in this subsection, such as records from the fuel supplier indicating the sulfur content of the fuel oil;

2) Retain the records for at least 5 years, and provide copies of the records to the Agency within 30 days of receipt of a request by the Agency; and

3) Notify the Agency within 30 days after discovery of deviations from any of the requirements in this subsection (b). At minimum,

and in addition to any permitting obligations, such notification must include a description of the deviations, a discussion of the possible cause of the deviations, any corrective actions taken, and any preventative measures taken.

c) The sulfur content limitation for distillate fuel oil in subsection (a)(2) of this Section does not apply to existing process emission sources at Caterpillar's Montgomery facility (located at or near 325 South Route 31, Montgomery, IL). The owner or operator of such process emission sources must instead comply with the following:

1) On and after January 1, 2016:

A) The sulfur content of all distillate fuel oil purchased for use by the process emission sources must not exceed 15 ppm; and

B) The sulfur content of all distillate fuel oil used by the process emission sources must not exceed 500 ppm;

2) The owner or operator must:

A) Maintain records demonstrating that the distillate fuel oil purchased on and after January 1, 2016, for use by the process emission sources complies with the requirements in subsection (c)(1)(A) of this Section, such as records from the fuel supplier indicating the sulfur content of the fuel oil, and maintain records indicating the date of purchase of the fuel oil;

B) Maintain records demonstrating that the distillate fuel oil used on and after January 1, 2016, by the process emission sources complies with the requirements in subsection (c)(1)(B) of this Section, such as records from the fuel supplier indicating the sulfur content of the fuel oil;

C) Retain all records required by this subsection (c) for at least 5 years, and provide copies of the records to the Agency within 30 days of receipt of a request by the Agency; and

D) Notify the Agency within 30 days after discovery of deviations from any of the requirements in this subsection (c). At minimum, and in addition to any permitting obligations, such notification must include a description of the deviations, a discussion of the possible cause of the deviations, any corrective actions taken, and any preventative measures taken.

d) The sulfur content limitation for distillate fuel oil in subsection (a)(2) of this Section does not apply to existing electric generating units at Midwest Generation's Fisk station (located at or near 1111 W. Cermak Road, Chicago, IL) or Waukegan station (located at or near 401 East Greenwood Avenue, Waukegan, IL). The owner or operator of such electric generating units must instead comply with the following:

1) From January 1, 2016, through December 31, 2018, the sulfur content of all distillate fuel oil purchased for use by such electric generating units must not exceed 15 ppm;

2) From January 1, 2017, through December 31, 2018, the sulfur content of all distillate fuel oil used by such electric generating units must not exceed 500 ppm;

3) On and after January 1, 2019, the sulfur content of all distillate fuel oil used by such electric generating units must not exceed 15 ppm;

4) The owner or operator must:

A) Maintain records demonstrating that the distillate fuel oil purchased from January 1, 2016, through December 31, 2018, for use by the electric generating units complies with the requirements in subsection (d)(1) of this Section, such as records from the fuel supplier indicating the sulfur content of the fuel oil, and maintain records indicating the date of purchase of the fuel oil;

B) Maintain records demonstrating that the distillate fuel oil used from January 1, 2017, through December 31, 2018, by the electric generating units complies with the requirements in subsection (d)(2) of this Section, such as records from the fuel supplier indicating the sulfur content of the fuel oil;

C) On and after January 1, 2019, maintain records demonstrating that the distillate fuel oil used by the electric generating units complies with the requirements in subsection (d)(3) of this Section, such as records from the fuel supplier indicating the sulfur content of the fuel oil;

D) Retain all records required by this subsection (d) for at least 5 years, and provide copies of the records to the Agency within 30 days of receipt of a request by the Agency; and

E) Notify the Agency within 30 days after discovery of deviations from any of the requirements in this subsection (d). At minimum, and in addition to any permitting obligations, such notification must include a description of the deviations, a discussion of the possible cause of the deviations, any corrective actions taken, and any preventative measures taken.

(Source: Added at 39 Ill. Reg. , effective)

SUBPART Q: PRIMARY AND SECONDARY METAL MANUFACTURING

Section 214.421 Combination of Fuels at Steel Mills in Metropolitan Areas

a) Section 214.162 notwithstanding, no person shall cause or allow the emission of sulfur dioxide into the atmosphere in any one hour period from any existing fuel combustion emission source at a steel mill located in the Chicago or St. Louis (Illinois) major metropolitan area burning any solid, liquid or gaseous fuel, or any combination thereof, to exceed the allowable emission rate determined by the following equation:

$$E = S_S H_S + S_d H_d + S_R H_R + S_G H_G$$

b) Symbols in the equation mean the following:

E = allowable sulfur dioxide emission rate;
S_S = solid fuel sulfur dioxide emission standard which is applicable;
S_d = distillate oil sulfur dioxide emission standard determined from the table in subsection (d);
S_R = residual oil sulfur dioxide emission standard which is applicable;
S_G = maximum by-product gas sulfur dioxide emissions which would result if the applicable by-product gas which was burned had been burned alone at any time during the 12

months preceding the latest operation, on or before March 28, 1983, of an emission source using any by-product gas.

H_S = actual heat input from solid fuel;
H_d = actual heat input from distillate fuel oil;
H_R = actual heat input from residual fuel oil;
H_G = actual heat input from by-product gases, such as those produced from a blast furnace.

c) That portion of the actual heat input that is derived:

1) From the burning of gaseous fuels produced by the gasification of solid fuels shall be included in H_S;

2) From the burning of gaseous fuels produced by the gasification of distillate fuel oil shall be included in H_d;

3) From the burning of gaseous fuels produced by the gasification of residual fuel oil shall be included in H_R; and

4) From the burning of gaseous fuels produced by the gasification of any other liquid fuel shall be included in H_G.

d) Metric or English units may be used in the equation of subsection (a) as follows:

Parameter	Metric	English
E	kg/hr	lbs/hr
S_S, S_R, S_G	kg/MW-hr	lbs/mmB~~b~~tu
S_d prior to January 1, 2017	0.46 kg/MW-hr	0.3 lbs/mmB~~b~~tu
S_d on and after January 1, 2017	0.0023 kg/MW-hr	0.0015 lb/mmBtu
H_S, H_d, H_R, H_G	MW	mmB~~b~~tu/hr

(Source: Amended at 39 Ill. Reg. , effective)

SUBPART AA: REQUIREMENTS FOR CERTAIN SO_2 SOURCES

Section 214.600 Definitions

For purposes of this Subpart, the following definitions apply. Unless a different meaning for a term is clear from its context, all terms not defined in this Section have the meaning given to them in the Illinois Environmental Protection Act and in 35 Ill. Adm. Code 201 and 211.

"Agency" means the Illinois Environmental Protection Agency.

"Aventine Renewable Energy" means the ethanol production source located at or near 1300 South 2nd Street, Pekin, IL.

"Illinois Power Holdings E.D. Edwards" means the electrical power generation source located at or near 7800 South Cilco Lane, Bartonville, IL.

"Ingredion Bedford Park" means the corn wet milling source located at or near 6400 South Archer Road, Bedford Park, IL.

"Midwest Generation Joliet" means the electrical power generation source located at or near 1800 Channahon Road, Joliet, IL.

"Midwest Generation Powerton" means the electrical power generation source located at or near 13082 E. Manito Road, Pekin, IL.

"Midwest Generation Will County" means the electrical power generation source located at or near 529 East 135th, Romeoville, IL.

"Owens Corning" means the asphalt and roofing products manufacturing source located at or near 5824 South Archer Road, Summit, IL.

"Oxbow Midwest Calcining" means the petroleum coke product source located at or near 12308 S. New Avenue, Lemont, IL.

(Source: Added at 39 Ill. Reg. , effective)

Section 214.601 Applicability

a) This Subpart applies to the following sources:

1) Aventine Renewable Energy;

2) Illinois Power Holdings E.D. Edwards;

3) Ingredion Bedford Park;

4) Midwest Generation Joliet;

5) Midwest Generation Powerton;

6) Midwest Generation Will County;

7) Owens Corning; and

8) Oxbow Midwest Calcining.

b) Once a source is subject to this Subpart, it is always subject to this Subpart, regardless of change in ownership or unit designation, or any other modification at the source.

c) Nothing in this Subpart relieves a source of the obligation to comply with the air quality standards set forth in 35 Ill. Adm. Code 243, or with any other applicable requirement set forth in this Part.

(Source: Added at 39 Ill. Reg. , effective)

Section 214.602 Compliance Deadline

On and after January 1, 2017, the owner or operator of a source identified in Section 214.601(a) of this Subpart must comply with the provisions in this Subpart.

(Source: Added at 39 Ill. Reg. , effective)

Section 214.603 Emission Limitations

The owner or operator of a source must comply with the following emission limitations, as applicable, expressed in terms of pounds of SO_2 emitted per clock hour.

a) Aventine Renewable Energy	lb/hr
1) Cyclone East controlling First Germ Drying System	0.27
2) Cyclone West controlling First Germ Drying System	0.37
3) Second Germ Drying System	0.01
4) Gluten Dryer 4	3.12
5) Gluten Dryer 9	10.50

6)	Germ Dryer 1	4.98
7)	Germ Dryer 3	4.26
8)	Yeast Dryer	1.50
9)	Scrubber controlling Steep Acid Tower	1.79
10)	Biogas Flare	0.001
11)	Boiler A	0.00
12)	Boiler B	0.00
13)	Boiler C	0.00

b) Illinois Power Holdings E.D. Edwards — lb/hr

1)	Units 1 and 2 combined	2100.00
2)	Unit 3	2756.00
3)	Unit 3, if both Units 1 and 2 permanently shut down	4000.00

c) Ingredion Bedford Park — lb/hr

1)	Feed Transport System	24.38
2)	Wet Milling: Inside In-Process Tanks	107.26
3)	Wet Milling: Molten Sulfur Burner and Absorption System	7.01
4)	Wet Milling: Outside In-Process Tanks	2.69
5)	Germ Processing Facility Channel 1 System	13.36
6)	Germ Processing Facility Channel 2 System	7.07

7)	Germ Processing Facility Channel 3 System	7.07
8)	Germ Processing Facility Channel 4 System	7.07

d) Midwest Generation Joliet — lb/hr

1)	Joliet 9: Unit 6	189.82
2)	Joliet 29: Unit 7	323.29
3)	Joliet 29: Unit 8	342.15

e) Midwest Generation Powerton — lb/hr

1)	Boilers 51, 52 (Unit 5) and 61, 62 (Unit 6) combined	3452.00

2) The owner or operator must comply with the emission limitation set forth in subsection (e)(1) of this Section on a 30-operating day rolling average basis. For purposes of this Subpart, an operating day is a calendar day in which any emission unit addressed in subsection (e)(1) of this Section combusts any fuel;

3) Within 24 hours of the end of each averaging period, the owner or operator must use the following equation to determine the combined SO_2 emission rate of the emission units addressed in subsection (e)(1) of this Section for each averaging period, which concludes at the end of each operating day. The SO_2 emission rate must not exceed the limitation set forth in subsection (e)(1) of this Section:

$$E_{avg} = \frac{\sum_{h=1}^{n} E_h}{n}$$

Where:

E_{avg} = SO_2 emission rate for the averaging period, in lb/hr.

E_h = SO_2 emission rate for stack operating hour "h" in the averaging period. For purposes of this Subpart, a stack operating hour is a clock hour in which valid data is obtained, and in which gases flow through the monitored stack or duct for the emission units addressed in subsection (e)(1) of this Section (either for part of the hour or for the entire hour) while at least one of the units is combusting fuel.

n = Number of stack operating hours in the averaging period in which valid data is obtained.

f) Midwest Generation Will County	lb/hr
1) Unit 3	145.14
2) Unit 4	6520.65
g) Owens Corning	lb/hr
1) Preheater Incinerator System 1, including emissions from: Storage Tanks 9, 9A, 10 10A, 11, 17, 18, 19, 20, 40, 41, 42, and 43; Loading Racks 1, 2, and 9; and Convertors 10 and 11	44.69
2) Preheater Incinerator System 3, including emissions from: Converters 8, 9, 12, 13, 14, and 15; and Loading Racks 1, 2, and 9	27.23
3) Regenerative Thermal Oxidizer 3 controlling: Storage Tanks 27, 28, 31, 32, 33, 34, 35, and 36	4.33
4) Regenerative Thermal Oxidizer 4 controlling: Storage Tank 98; Loading Rack PV1	6.38
5) Coating Operations combined	0.15
h) Oxbow Midwest Calcining	lb/hr
All Calcining Units combined	187.00

(Source: Added at 39 Ill. Reg. , effective)

Section 214.604 Monitoring and Testing

a) The owner or operator of a source must, for each emission unit at the source that is addressed in Section 214.603 of this Subpart, demonstrate compliance with the applicable emission limitations in Section 214.603 of this Subpart via the monitoring and testing requirements set forth in this Section.

b) The owners or operators of the following sources must, for each emission unit at the source that is addressed in Section 214.603 of this Subpart, install, calibrate, maintain, and operate a continuous emissions monitoring system for the measurement of SO_2 emissions in accordance with 40 CFR 75 (except 40 CFR 75.31-34), incorporated by reference in Section 214.104 of this Part, and subsection (d) of this Section, or utilize an alternative monitoring method available to the emission unit under 40 CFR 75:

1) Illinois Power Holdings E.D. Edwards;

2) Midwest Generation Joliet;

3) Midwest Generation Powerton; and

4) Midwest Generation Will County.

c) The owner or operator of all sources not addressed in subsection (b) of this Section must, for each emission unit at the source that is addressed in Section 214.603 of this Subpart, either conduct performance testing in accordance with subsection (e) of this Section or install, calibrate, maintain, and operate a continuous emissions monitoring system for the measurement of SO_2 emissions in accordance with 40 CFR 60 or 40 CFR 75 (except 40 CFR 75.31-34), incorporated by reference in Section 214.104 of this Part, and subsection (d) of this Section.

d) The owner or operator of a source with an emission unit demonstrating compliance through the use of a continuous emissions monitoring system must comply with the following for each such unit:

1) If two or more of the emission units addressed in Section 214.603 of this Subpart are served by a common stack, the owner or operator may utilize a single continuous emissions monitoring system for such units;

2) If the owner or operator of an emission unit subject to Section 214.604(c) of this Subpart changes the method of demonstrating compliance for such unit from performance testing to use of a continuous emissions monitoring system, the owner or operator must install, calibrate, and begin operating the continuous emissions monitoring system on or before the performance testing deadline determined in accordance with subsection (e)(2) of this Section; and

3) The provisions in 40 CFR 75.31-34 regarding missing data substitution must not be used for purposes of demonstrating compliance with the requirements set forth in this Subpart.

e) The owner or operator of a source with an emission unit demonstrating compliance through performance testing must comply with the following for each such unit. All testing done pursuant to this Section must be conducted at the owner or operator's own expense:

1) Conduct an initial performance test after January 1, 2015, and prior to January 1, 2017. If the owner or operator of an emission unit subject to Section 214.604(c) of this Subpart changes the method of demonstrating compliance for such unit from use of a continuous emissions monitoring system to performance testing, the owner or operator must demonstrate compliance by conducting an initial performance test prior to discontinuing the continuous emissions monitoring system;

2) Conduct subsequent performance tests at least once every 5 years from the date of the last performance test. The date of the initial performance test conducted pursuant to subsection (e)(1) of this Section begins the 5-year period;

3) Conduct additional performance testing when, in the opinion of the Agency or USEPA, such testing is necessary to demonstrate compliance with the requirements in Section 214.603 of this Subpart. Such test must be conducted within 90 days after receipt of a notice to test from the Agency or USEPA, unless the notice specifies an alternative testing deadline;

4) Submit a testing protocol as described in USEPA's Emission Measurement Center Guideline Document (GD-042), incorporated by reference in Section 214.104 of this Part, to the Agency at least

45 days prior to a scheduled emissions test, unless such deadline is waived in writing by the Agency;

5) Submit a written notification of a scheduled emissions test to the Agency at least 30 days prior to the test date and again 5 days prior to testing, unless such deadlines are waived in writing by the Agency. If, after the 30 days' notice of a test is sent, there is a delay in conducting the test as scheduled (e.g., due to operational problems), the owner or operator must notify the Agency as soon as practicable of the delay, either by providing at least 7 days' notice of the rescheduled test date or by arranging a new test date with the Agency by mutual agreement;

6) Conduct each performance test using Methods 1, 2, 3, 4, 6, 6A, 6B, 6C, or 19, incorporated by reference in Section 214.104 of this Part, or other alternative USEPA methods approved by the Agency. Each test must consist of at least 3 separate runs, each lasting a minimum of 60 minutes, and must be conducted during conditions representative of maximum SO_2 emissions. Compliance with the applicable limitation in Section 214.603 of this Subpart must be determined in accordance with 35 Ill. Adm. Code 283;

7) If the unit has combusted more than one type of fuel in the prior year, a separate performance test is required for each fuel; and

8) Subsequent to each performance test used to demonstrate compliance, continue operating the emission unit within the parameters enumerated in the testing results submitted to the Agency for such test, and monitor the parameters regularly to ensure ongoing compliance.

(Source: Added at 39 Ill. Reg. , effective)

Section 214.605 Recordkeeping and Reporting

a) By January 1, 2017, the owner or operator of a source must submit to the Agency the following:

1) A certification that the source will be in compliance with the provisions in this Subpart by January 1, 2017;

2) For a source with an emission unit demonstrating compliance through performance testing:

A) The results of the initial performance test conducted pursuant to Section 214.604(e)(1) of this Subpart;

B) The calculations necessary to demonstrate that the emission unit will be in initial compliance; and

C) A description of the measures the source will take to ensure the emission unit continues to operate within the parameters enumerated in the testing results submitted to the Agency for each test used to demonstrate compliance, including how such parameters will ensure ongoing compliance with the applicable limitation in Section 214.603 of this Subpart and the specific monitoring procedures that will be implemented for each parameter;

3) For a source with an emission unit demonstrating compliance through the use of a continuous emissions monitoring system, a certification of the installation and operation of the continuous emissions monitoring system and the monitoring data necessary to demonstrate that the emission unit will be in initial compliance;

4) For a source with an emission unit demonstrating compliance through the use of an alternative monitoring method under 40 CFR 75, a description of the alternative monitoring method being used and the monitoring data necessary to demonstrate that the emission unit will be in initial compliance; and

5) A description of the method(s) the source will use to comply with all applicable emission limitations in Section 214.603 of this Subpart, including a description of all control devices used and, for sources with emission units demonstrating compliance through performance testing, the operating parameters for such devices.

b) The owner or operator of a source must keep and maintain records that demonstrate ongoing compliance with the requirements of this Subpart. Such records must include the following:

1) The calendar date of the record;

2) Reports for all performance tests conducted pursuant to Section 214.604(e) of this Subpart, including the date of the test and the results;

3) A log of the date, time, nature, and results of all parametric monitoring conducted pursuant to Section 214.604(e)(8) of this Subpart;

4) For each SO_2 continuous emissions monitoring system, a log indicating any periods when the device was not in service, maintenance and inspection activities performed on the device, and all information necessary to demonstrate compliance with the monitoring requirements in Section 214.604 of this Subpart;

5) The date, time, and duration of any malfunction in the operation of an emission unit addressed in Section 214.603 of this Subpart or any SO_2 control equipment for such unit, if such malfunction causes an exceedance of any applicable emission limitation in Section 214.603 of this Subpart, and the date, time, and duration of any malfunction in the operation of any SO_2 emissions monitoring equipment for such unit. The records must include a description of the malfunction, the probable cause of the malfunction, the date and nature of the corrective action taken, and any preventative action taken to avoid future malfunctions;

6) A log of all inspections, cleaning, maintenance, and repair activities performed on SO_2 control equipment for an emission unit addressed in Section 214.603 of this Subpart, including the date and nature of such activities. Such log must indicate any changes made to the control equipment, including removal or replacement of the equipment; and

7) For emission units subject to the emission limitation in Section 214.603(e) of this Subpart, the SO_2 emission rate of the units for each averaging period and supporting calculations.

c) Except as otherwise indicated in this Subpart, the owner or operator of a source with an emission unit demonstrating compliance through performance testing must submit the results of all tests conducted pursuant to Section 214.604(e) of this Subpart within 60 days after completion of the test.

d) The owner or operator of a source must notify the Agency at least 30 days prior to changing the method of demonstrating compliance for an emission unit addressed in Section 214.603 of this Subpart. The owner or operator must also comply with the following, as applicable:

1) For an emission unit changing the method of demonstrating compliance from performance testing to use of a continuous emissions monitoring system, submit to the Agency a certification of the installation and operation of the continuous emissions monitoring system and the monitoring data necessary to demonstrate compliance. Such submittal must be made within 30 days after beginning operation of the continuous emissions monitoring system, and on or before the performance testing deadline determined in accordance with Section 214.604(e)(2) of this Subpart;

2) For an emission unit changing the method of demonstrating compliance from use of a continuous emissions monitoring system to performance testing, submit to the Agency the following. Such submittal must be made prior to discontinuing operation of the continuous emissions monitoring system:

A) The results of the initial performance test conducted pursuant to Section 214.604(e)(1) of this Subpart;

B) The calculations necessary to demonstrate compliance; and

C) A description of the measures the source will take to ensure the emission unit continues to operate within the parameters enumerated in the testing results submitted to the Agency for each test used to demonstrate compliance, including how such parameters will ensure ongoing compliance with the applicable limitation in Section 214.603 of this Subpart and the specific monitoring procedures that will be implemented for each parameter;

3) For an emission unit changing the method of demonstrating compliance from use of a continuous emissions monitoring system to an alternative monitoring method under 40 CFR 75, submit to the Agency a description of the alternative monitoring method being used and the monitoring data necessary to demonstrate compliance. Such submittal must be made prior to discontinuing operation of the continuous emissions monitoring system.

e) The owner or operator of a source must notify the Agency within 30 days after discovery of deviations from any of the requirements in this Subpart or any exceedance of an applicable emission limitation in Section 214.603 of this Subpart. At minimum, and in addition to any permitting obligations, such notification must include a description of the deviations or exceedances, a discussion of the possible cause of the deviations or exceedances, any corrective actions taken, and any preventative measures taken.

f) The owner or operator of a source must maintain all records required by this Section at the source for a minimum of 5 years, and provide copies of such records to the Agency within 30 days of receipt of a request by the Agency.

(Source: Added at 39 Ill. Reg. , effective)

TITLE 35: ENVIRONMENTAL PROTECTION
SUBTITLE B: AIR POLLUTION
CHAPTER I: POLLUTION CONTROL BOARD
SUBCHAPTER c: EMISSION STANDARDS AND LIMITATIONS FOR STATIONARY SOURCES

PART 225
CONTROL OF EMISSIONS FROM LARGE COMBUSTION SOURCES

SUBPART A: GENERAL PROVISIONS

Section

SUBPART B: CONTROL OF MERCURY EMISSIONS FROM COAL-FIRED ELECTRIC GENERATING UNITS

Section

225.295 Combined Pollutant Standard: Emissions Standards for NO_x and SO_2
225.296 Combined Pollutant Standard: Control Technology Requirements for NO_x, SO_2, and PM Emissions
225.297 Combined Pollutant Standard: Permanent Shut-Downs
225.298 Combined Pollutant Standard: Requirements for NO_x and SO_2 Allowances
225.299 Combined Pollutant Standard: Clean Air Act Requirements

SUBPART C: CLEAN AIR ACT INTERSTATE RULE (CAIR) SO_2 TRADING PROGRAM

Section
225.300 Purpose
225.305 Applicability
225.310 Compliance Requirements
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SUBPART D: CAIR NO_x ANNUAL TRADING PROGRAM

Section
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225.405 Applicability
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225.445 New Unit Set-Aside (NUSA)
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225.460 Energy Efficiency and Conservation, Renewable Energy, and Clean Technology Projects
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SUBPART E: CAIR NO_x OZONE SEASON TRADING PROGRAM

Section
225.500 Purpose
225.505 Applicability
225.510 Compliance Requirements

AUTHORITY: Implementing and authorized by Section 27 of the Environmental Protection Act [415 ILCS 5/27].

SOURCE: Adopted in R06-25 at 31 Ill. Reg. 129, effective December 21, 2006; amended in R06-26 at 31 Ill. Reg. 12864, effective August 31, 2007; amended in R09-10 at 33 Ill. Reg. 10427, effective June 26, 2009.

SUBPART B: CONTROL OF MERCURY EMISSIONS FROM COAL-FIRED ELECTRIC GENERATING UNITS

Section 225.205 Applicability

The following stationary coal-fired boilers and stationary coal-fired combustion turbines, and the stationary boilers listed in Appendix A of this Part regardless of the type of fuel combusted, are EGUs and are subject to this Subpart B:

a) Except as provided in subsection (b) of this Section, a unit serving, at any time since the start-up of the unit's combustion chamber, a generator with nameplate capacity of more than 25 MWe producing electricity for sale.

b) For a unit that qualifies as a cogeneration unit during the 12-month period starting on the date the unit first produces electricity and continues to qualify as a cogeneration unit, a cogeneration unit serving at any time a generator with nameplate capacity of more than 25 MWe and supplying in any calendar year more than one-third of the unit's potential electric output capacity or 219,000 MWh, whichever is greater, to any utility power distribution system for sale. If a unit qualifies as a cogeneration unit during the 12-month period starting on the date the unit first produces electricity but subsequently no longer qualifies as a cogeneration unit, the unit must be subject to subsection (a) of this Section starting on the day on which the unit first no longer qualifies as a cogeneration unit.

(Source: Amended at 39 Ill. Reg. , effective)

Section 225.210 Compliance Requirements

a) Permit Requirements.

The owner or operator of each source with one or more EGUs subject to this Subpart B at the source must apply for a CAAPP permit that addresses the applicable requirements of this Subpart B.

b) Monitoring and Testing Requirements.

1) Except as otherwise indicated in this Subpart, the~~The~~ owner or operator of each source and each EGU at the source must comply with either the monitoring requirements of Sections 225.240 through 225.290 of this Subpart B, the periodic emissions testing requirements of Section 225.239 of this Subpart B, or an alternative emissions monitoring system, alternative reference method for measuring emissions, or other alternative to the emissions monitoring and measurement requirements of Sections 225.240 through 225.290, if such alternative is submitted to the Agency in writing and approved in writing by the Manager of the Bureau of Air's Compliance Section.

2) Except as otherwise indicated in this Subpart, the~~The~~ compliance of each EGU with the mercury requirements of Sections 225.230 and 225.237 of this Subpart B must be determined by the emissions measurements recorded and reported in accordance with either Sections 225.240 through 225.290 of this Subpart B, Section 225.239 of this Subpart B, or an alternative emissions monitoring system, alternative reference method for measuring emissions, or other alternative to the emissions monitoring and measurement requirements of Sections 225.240 through 225.290, if such alternative is submitted to the Agency in writing and approved in writing by the Manager of the Bureau of Air's Compliance Section.

c) Mercury Emission Reduction Requirements

The owner or operator of any EGU subject to this Subpart B must comply with applicable requirements for control of mercury emissions of Section 225.230 or Section 225.237 of this Subpart B.

d) Recordkeeping and Reporting Requirements

Unless otherwise provided, the owner or operator of a source with one or more EGUs at the source must keep on site at the source each of the documents listed in subsections (d)(1) through (d)(3) of this Section for a period of five years from the date the document is created. This period may be extended, in writing by the Agency, for cause, at any time prior to the end of five years.

1) All emissions monitoring information gathered in accordance with Sections 225.240 through 225.290 and all periodic emissions testing information gathered in accordance with Section 225.239.

2) Copies of all reports, compliance certifications, and other submissions and all records made or required or documents necessary to demonstrate compliance with the requirements of this Subpart B.

3) Copies of all documents used to complete a permit application and any other submission under this Subpart B.

e) Liability.

1) The owner or operator of each source with one or more EGUs must meet the requirements of this Subpart B.

2) Any provision of this Subpart B that applies to a source must also apply to the owner and operator of such source and to the owner or operator of each EGU at the source.

3) Any provision of this Subpart B that applies to an EGU must also apply to the owner or operator of such EGU.

f) Effect on Other Authorities. No provision of this Subpart B may be construed as exempting or excluding the owner or operator of a source or EGU from compliance with any other provision of an approved State Implementation Plan, a permit, the Act, or the CAA.

(Source: Amended at 39 Ill. Reg. , effective)

Section 225.240 General Monitoring and Reporting Requirements

Except as otherwise indicated in this Subpart, the~~The~~ owner or operator of an EGU must comply with the monitoring, recordkeeping, and reporting requirements as provided in this Section, Sections 225.250 through 225.290 of this Subpart B, and Sections 1.14 through 1.18 of Appendix B to this Part. If the EGU utilizes a common stack with units that are not EGUs and the owner or operator of the EGU does not conduct emissions monitoring in the duct to the common stack from each EGU, the owner or operator of the EGU must conduct emissions monitoring in accordance with Section 1.16(b)(2) of Appendix B to this Part and this Section, including monitoring in the duct to the common stack from each unit that is not an EGU, unless the owner or operator of the EGU counts the combined emissions measured at the common stack as the mass emissions of mercury for the EGUs for recordkeeping and compliance purposes.

a) Requirements for installation, certification, and data accounting. The owner or operator of each EGU must:

1) Install all monitoring systems required pursuant to this Section and Sections 225.250 through 225.290 for monitoring mercury mass emissions (including all systems required to monitor mercury concentration, stack gas moisture content, stack gas flow rate, and CO_2 or O_2 concentration, as applicable, in accordance with Sections 1.15 and 1.16 of Appendix B to this Part).

2) Successfully complete all certification tests required pursuant to Section 225.250 and meet all other requirements of this Section, Sections 225.250 through 225.290, and Sections 1.14 through 1.18 of Appendix B to this Part applicable to the monitoring systems required under subsection (a)(1) of this Section.

3) Record, report, and assure the quality of the data from the monitoring systems required under subsection (a)(1) of this Section.

4) If the owner or operator elects to use the low mass emissions excepted monitoring methodology for an EGU that emits no more than 464 ounces (29 pounds) of mercury per year pursuant to Section 1.15(b) of Appendix B to this Part it must perform emissions testing in accordance with Section

1.15(c) of Appendix B to this Part to demonstrate that the EGU is eligible to use this excepted emissions monitoring methodology, as well as comply with all other applicable requirements of Section 1.15(b) through (f) of Appendix B to this Part. Also, the owner or operator must submit a copy of any information required to be submitted to the USEPA pursuant to these provisions to the Agency. The initial emissions testing to demonstrate eligibility of an EGU for the low mass emissions excepted methodology must be conducted by the applicable of the following dates:

A) If the EGU has commenced commercial operation before July 1, 2008, at least by July 1, 2009, or 45 days prior to relying on the low mass emissions excepted methodology, whichever date is later.

B) If the EGU has commenced commercial operation on or after July 1, 2008, at least 45 days prior to the applicable date specified pursuant to subsection (b)(2) of this Section or 45 days prior to relying on the low mass emissions excepted methodology, whichever date is later.

b) Emissions Monitoring Deadlines. The owner or operator must meet the emissions monitoring system certification and other emissions monitoring requirements of subsections (a)(1) and (a)(2) of this Section on or before the applicable of the following dates. The owner or operator must record, report, and quality-assure the data from the emissions monitoring systems required under subsection (a)(1) of this Section on and after the applicable of the following dates:

1) For the owner or operator of an EGU that commences commercial operation before July 1, 2008, by July 1, 2009, except that an EGU in an MPS Group for which an SO_2 scrubber or fabric filter is being installed to be in operation by December 31, 2009, as described in Section 225.233(c)(1)(A), shall have a date of January 1, 2010.

2) For the owner or operator of an EGU that commences commercial operation on or after July 1, 2008, by 90 unit operating days or 180 calendar days, whichever occurs first, after the date on which the EGU commences commercial operation.

3) For the owner or operator of an EGU for which construction of a new stack or flue or installation of add-on mercury emission controls, a flue gas desulfurization system, a selective catalytic reduction system, a fabric filter, or a compact hybrid particulate collector system is completed after the applicable deadline pursuant to subsection (b)(1) or (b)(2) of this Section, by 90 unit operating days or 180 calendar days, whichever occurs first, after the date on which emissions first exit to the atmosphere through the new stack or flue, add-on mercury emission controls, flue gas

desulfurization system, selective catalytic reduction system, fabric filter, or compact hybrid particulate collector system.

4) For an owner or operator of an EGU that originally elected to demonstrate compliance pursuant to the emissions testing requirements in Section 225.239, by the first day of the calendar quarter following the last emissions test demonstrating compliance with Section 225.239.

c) The owner or operator of an EGU that does not meet the applicable emissions monitoring date set forth in subsection (b) of this Section for any emissions monitoring system required pursuant to subsection (a)(1) of this Section must begin periodic emissions testing in accordance with Section 225.239.

d) Prohibitions.

1) No owner or operator of an EGU may use any alternative emissions monitoring system, alternative reference method for measuring emissions, or other alternative to the emissions monitoring and measurement requirements of this Section and Sections 225.250 through 225.290, unless such alternative is submitted to the Agency in writing and approved in writing by the Manager of the Bureau of Air's Compliance Section, or his or her designee.

2) No owner or operator of an EGU may operate its EGU so as to discharge, or allow to be discharged, mercury emissions to the atmosphere without accounting for such emissions in accordance with the applicable provisions of this Section, Sections 225.250 through 225.290, and Sections 1.14 through 1.18 of Appendix B to this Part, unless demonstrating compliance pursuant to Section 225.239, as applicable.

3) No owner or operator of an EGU may disrupt the CEMS (or excepted monitoring system), any portion thereof, or any other approved emission monitoring method, and thereby avoid monitoring and recording mercury mass emissions discharged into the atmosphere, except for periods of recertification or periods when calibration, quality assurance testing, or maintenance is performed in accordance with the applicable provisions of this Section, Sections 225.250 through 225.290, and Sections 1.14 through 1.18 of Appendix B to this Part.

4) No owner or operator of an EGU may retire or permanently discontinue use of the CEMS (or excepted monitoring system) or any component thereof, or any other approved monitoring system pursuant to this Subpart B, except under any one of the following circumstances:

A) The owner or operator is monitoring emissions from the EGU with another certified monitoring system that has been approved, in accordance with the applicable provisions of this Section, Sections 225.250 through 225.290 of this Subpart B, and Sections 1.14 through 1.18 of Appendix B to this Part, by the Agency for use at that EGU and that provides emission data for the same pollutant or parameter as the retired or discontinued monitoring system; or

B) The owner or operator submits notification of the date of certification testing of a replacement monitoring system for the retired or discontinued monitoring system in accordance with Section 225.250(a)(3)(A).

C) The owner or operator is demonstrating compliance pursuant to the applicable subsections of Section 225.239.

e) Long-term Cold Storage.

The owner or operator of an EGU that is in long-term cold storage is subject to the provisions of 40 CFR 75.4 and 40 CFR 75.64, incorporated by reference in Section 225.140, relating to monitoring, recordkeeping, and reporting for units in long-term cold storage.

(Source: Amended at 39 Ill. Reg. , effective)

Section 225.265 Coal Analysis for Input Mercury Levels

a) The owner or operator of an EGU complying with this Subpart B by means of Section 225.230(a)(1)(B); using input mercury levels (I_i) and complying by means of Section 225.230(b) or (d) or Section 225.232; electing to comply with the emissions testing, monitoring, and recordkeeping requirements under Section 225.239; demonstrating compliance under Section 225.233, except an EGU in an MPS Group that elects to comply with the emission standard in Section 225.233(d)(1)(A) or (d)(2)(A); or demonstrating compliance under Sections 225.291 through 225.299, except an EGU in a CPS Group that elects to comply with the emission standard in Section 225.294(c)(1) or that opts into the emission standard in Section 225.294(c)(1) pursuant to Section 225.294(e)(1) <u>or that has permanently ceased combusting coal,</u> must fulfill the following requirements:

1) Perform sampling of the coal combusted in the EGU for mercury content. The owner or operator of such EGU must collect a minimum of one 2-lb. grab sample from the belt feeders anywhere between the crusher house or breaker building and the boiler or, in cases in which a crusher house or breaker building is not present, at a reasonable point close to the boiler of a subject EGU, according to the schedule in subsections (a)(1)(A) through (C). The sample must be taken in a manner that provides representative mercury content for the coal burned on that day. If multiple samples are tested, the owner or operator must average those tests to arrive at the final

mercury content for that time period. The owner or operator of the EGU must perform coal sampling as follows:

A) EGUs complying by means of Section 225.233, except an EGU in an MPS Group that elects to comply with the control efficiency standard in Section 225.233(d)(1)(B) or (d)(2)(B) or elects to comply with Section 225.233(d)(4), or Sections 225.291 through 225.299, except an EGU in a CPS Group that elects to comply with the control efficiency standard in Section 225.294(c)(2) or that opts into the emission standard in Section 225.294(c)(2) pursuant to Section 225.294(e)(1) must perform such coal sampling at least once per month unless the boiler did not operate or combust coal at all during that month;

B) EGUs complying by means of the emissions testing, monitoring, and recordkeeping requirements under Section 225.239 or Section 225.233(d)(4), or EGUs that opt into the emission standard in Section 225.294(c)(2) pursuant to Section 225.294(e)(1)(B), must perform such coal sampling according to the schedule provided in Section 225.239(e)(3) of this Subpart;

C) All other EGUs subject to this requirement, including EGUs in an MPS or CPS Group electing to comply with the control efficiency standard in Section 225.233(d)(1)(B) or (d)(2)(B), Section 225.294(c)(2), or Section 225.294(c)(2) pursuant to Section 225.294(e)(1)(A), must perform such coal sampling on a daily basis when the boiler is operating and combusting coal.

2) Analyze the grab coal sample for the following:

A) Determine the heat content using ASTM D5865-04 or an equivalent method approved in writing by the Agency.

B) Determine the moisture content using ASTM D3173-03 or an equivalent method approved in writing by the Agency.

C) Measure the mercury content using ASTM D6414-01, ASTM D3684-01, ASTM D6722-01, or an equivalent method approved in writing by the Agency.

3) The owner or operator of multiple EGUs at the same source using the same crusher house or breaker building may take one sample per crusher house or breaker building, rather than one per EGU.

4) The owner or operator of an EGU must use the data analyzed pursuant to subsection (b) of this Section to determine the mercury content in terms of parts per million.

b) The owner or operator of an EGU that must conduct sampling and analysis of coal pursuant to subsection (a) of this Section must begin such activity by the following date:

1) If the EGU is in daily service, at least 30 days before the start of the month for which such activity will be required.

2) If the EGU is not in daily service, on the day that the EGU resumes operation.

(Source: Amended at 39 Ill. Reg. , effective)

Section 225.290 Recordkeeping and Reporting

a) General Provisions.

1) Except as otherwise indicated in this Subpart, the~~The~~ owner or operator of an EGU must comply with all applicable recordkeeping and reporting requirements in this Section and with all applicable recordkeeping and reporting requirements of Section 1.18 to Appendix B to this Part.

2) The owner or operator of an EGU must maintain records for each month identifying the emission standard in Section 225.230(a) or 225.237(a) of this Section with which it is complying or that is applicable for the EGU and the following records related to the emissions of mercury that the EGU is allowed to emit:

A) For an EGU for which the owner or operator is complying with this Subpart B by means of Section 225.230(a)(1)(B) or 225.237(a)(1)(B) or using input mercury levels to determine the allowable emissions of the EGU, records of the daily mercury content of coal used (parts per) and the daily and monthly input mercury (lbs), which must be kept in the file pursuant to Section 1.18(a) of Appendix B to this Part.

B) For an EGU for which the owner or operator of an EGU complying with this Subpart B by means of Section 225.230(a)(1)(A) or 225.237(a)(1)(A) or using electrical output to determine the allowable emissions of the EGU, records of the daily and monthly gross electrical output (GWh), which must be kept in the file required pursuant to Section 1.18(a) of Appendix B to this Part.

3) The owner or operator of an EGU must maintain records of the following data for each EGU:

A) Monthly emissions of mercury from the EGU.

B) For an EGU for which the owner or operator is complying by means of Section 225.230(b) or (d) of this Subpart B, records of the monthly allowable emissions of mercury from the EGU.

4) The owner or operator of an EGU that is participating in an Averaging Demonstration pursuant to Section 225.232 of this Subpart B must maintain records identifying all sources and EGUs covered by the Demonstration for each month and, within 60 days after the end of each calendar month, calculate and record the actual and allowable mercury emissions of the EGU for the month and the applicable 12-month rolling period.

5) The owner or operator of an EGU must maintain the following records related to quality assurance activities conducted for emissions monitoring systems:

A) The results of quarterly assessments conducted pursuant to Section 2.2 of Exhibit B to Appendix B to this Part; and

B) Daily/weekly system integrity checks pursuant to Section 2.6 of Exhibit B to Appendix B to this Part.

6) The owner or operator of an EGU must retain all records required by this Section at the source for a period of five years from the date the document is created unless otherwise provided in the CAAPP permit issued for the source and must make a copy of any record available to the Agency upon request. This period may be extended in writing by the Agency, for cause, at any time prior to the end of five years.

b) Quarterly Reports. The owner or operator of a source with one or more EGUs using CEMS or excepted monitoring systems at any time during a calendar quarter must submit quarterly reports to the Agency as follows:

1) Source information such as source name, source ID number, and the period covered by the report~~;~~.

2) A list of all EGUs at the source that identifies the applicable Part 225 monitoring and reporting requirements with which each EGU is complying for the reported quarter, including the following EGUs, which are excluded from subsection (b)(3) of this Section:

A) All EGUs using the periodic emissions testing provisions of Section 225.239, 225.233(d)(4), or Section 225.294(c) pursuant to Section 225.294(e)(1)(B) for the quarter.

B) All EGUs using the low mass emissions (LME) excepted monitoring methodology pursuant to Section 1.15(b) of Appendix B to this Part.

3) For only those EGUs using CEMS or excepted monitoring systems at any time during a calendar quarter:

A) An indication of whether the identified EGUs were in compliance with all applicable monitoring, recordkeeping, and reporting requirements of Part 225 for the entire reporting period.

B) The total quarterly operating hours of each EGU.

C) The CEMS or excepted monitoring system QAMO hours on a quarterly basis and percentage data availability on a quarterly or rolling 12-month basis (for each concluding 12-month period in that quarter), as appropriate according to the schedule provided in Section 225.260(b). The data availability shall be determined in accordance with Section~~s~~ 1.8 (CEMS) or 1.9 (excepted monitoring system) of Appendix B to this Part.

D) The average monthly mercury concentration of the coal combusted in each EGU in parts per million (determined by averaging all analyzed coal samples in the month) and the quarterly total amount of mercury (calculated by multiplying the total amount of coal combusted each month by the average monthly mercury concentration and converting to ounces, then adding together for the quarter) of the coal combusted in each EGU. If the EGU is complying by means of Section~~s~~ 225.230(a)(1)(A), 225.233(d)(1)(A), 225.233(d)(2)(A), or 225.294(c)(1), reporting of the data in this subsection (b)(3)(D) is not required.

E) The quarterly mercury mass emissions (in ounces), determined from the QAMO hours in accordance with Section 4.2 of Exhibit C to Appendix B to this Part. If the EGU is complying by means of Section 225.230(a)(1)(A), 225.233(d)(1)(A), 225.233(d)(2)(A), or 225.294(c)(1), reporting of the data in this subsection (b)(3)(E) is not required.

F) The average monthly and quarterly mercury control efficiency. This is determined by dividing the mercury mass emissions recorded during QAMO hours, calculated each month and quarter, by the total amount of mercury in the coal combusted weighted by the monitor availability (total mercury content multiplied by the percent monitor availability, or QAMO hours divided by total hours) for each month and quarter. If the DAHS for the EGU has the ability to record the amount of coal combusted during QAMO hours, the average monthly and quarterly control efficiency shall be reported without the calculation in this subsection (b)(3)(F). If the EGU is complying by means of Section~~s~~ 225.230(a)(1)(A), 225.233(d)(1)(A), 225.233(d)(2)(A), or 225.294(c)(1), reporting of the data in this subsection (b)(3)(F) is not required.

G) The average monthly and quarterly mercury emission rate (in lb/GWh) for each EGU, determined in accordance with Section 225.230(a)(2). Only those EGUs complying by means of Section 225.230(a)(1)(A), 225.233(d)(1)(A), 225.233(d)(2)(A), or 225.294(c)(1) are required to report the data in this subsection (b)(3)(G).

H) The 12-month rolling average control efficiency (percentage) or emission rate (in lb/GWh) for each month in the reporting period, as applicable (or the rolling average control efficiency or emission rate for a lesser number of months if a full 12 months of data is not available). This applicable data is determined according to the following requirements:

i) The 12-month rolling average control efficiency is required for those sources complying by means of Section 225.230(a)(1)(B), 225.233(d)(1)(B), 225.233(d)(2)(B), 225.294(c)(2), 225.230(b), 225.230(d), 225.232(b)(2), or 225.237(a)(1)(B).

ii) The 12-month rolling average emission rate is required for those sources complying by means of Section 225.230(a)(1)(A), 225.233(d)(1)(A), 225.233(d)(2)(A), or 225.294(c)(1), 225.230(b), 225.230(d), 225.232(b)(1), or 225.237(a)(1)(A).

I) If the CEMS or excepted monitoring system percentage data availability was less than 95.0 percent of the total operating time for the EGU, the date and time identifying each period during which the CEMS was inoperative, except for routine zero and span checks; the nature of CEMS repairs or adjustments and a summary of quality assurance data consistent with Appendix B to this Part, i.e., the dates and results of the Linearity Tests and any RATAs during the quarter; a listing of any days when a required daily calibration was not performed; and the date and duration of any periods when the CEMS was unavailable or out-of-control as addressed by Section 225.260.

4) The owner or operator must submit each quarterly report to the Agency within 45 days following the end of the calendar quarter covered by the report, except that the owner or operator of an EGU that used an excepted monitoring system at any time during a calendar quarter must submit each quarterly report within 60 days following the end of the calendar quarter covered by the report.

c) Compliance Certification. The owner or operator of a source with one or more EGUs must submit to the Agency a compliance certification in support of each quarterly report based on reasonable inquiry of those persons with primary responsibility for ensuring that all of the EGUs' emissions are correctly and fully monitored. The certification must state:

1) That the monitoring data submitted were recorded in accordance with the applicable requirements of this Section, Sections 225.240 through 225.270 and Section 225.290 of this Subpart B, and Appendix B to this Part, including the quality assurance procedures and specifications; and

2) For an EGU with add-on mercury emission controls, a flue gas desulfurization system, a selective catalytic reduction system, or a compact hybrid particulate collector system for all hours where mercury data is unavailable or out-of-control that:

A) The mercury add-on emission controls, flue gas desulfurization system, selective catalytic reduction system, or compact hybrid particulate collector system was operating within the range of parameters listed in the quality assurance/quality control program pursuant to Exhibit B to Appendix B to this Part; or

B) With regard to a flue gas desulfurization system or a selective catalytic reduction system, quality-assured SO_2 emission data recorded in accordance with the 40 CFR 75 document that the flue gas desulfurization system was operating properly, or quality-assured NO_X emission data recorded in accordance with the 40 CFR 75 document that the selective catalytic reduction system was operating properly, as applicable.

d) Annual Certification of Compliance.

1) The owner or operator of a source with one or more EGUs subject to this Subpart B must submit to the Agency an Annual Certification of Compliance with this Subpart B no later than May 1 of each year and must address compliance for the previous calendar year. Such certification

must be submitted to the Agency, Air Compliance Section, and the Air Regional Field Office.

2) Annual Certifications of Compliance must indicate whether compliance existed for each EGU for each month in the year covered by the Certification and it must certify to that effect. In addition, for each EGU, the owner or operator must provide the following appropriate data as set forth in subsections (d)(2)(A) through (d)(2)(E) of this Section, together with the data set forth in subsection (d)(2)(F) of this Section:

A) If complying with this Subpart B by means of Section 225.230(a)(1)(A) or 225.237(a)(1)(A):

i) Emissions rate during QAMO hours, in lb/GWh, for each 12-month rolling period ending in the year covered by the Certification;

ii) Emissions during QAMO hours, in lbs, and gross electrical output, in GWh, for each 12-month rolling period ending in the year covered by the Certification; and

iii) Emissions during QAMO hours, in lbs, and gross electrical output, in GWh, for each month in the year covered by the Certification and in the previous year.

B) If complying with this Subpart B by means of Section 225.230(a)(1)(B) or 225.237(a)(1)(B):

i) Control efficiency for emissions during QAMO hours for each 12-month rolling period ending in the year covered by the Certification, expressed as a percent;

ii) Emissions during QAMO hours, in lbs, and mercury content in the fuel fired in such EGU, in lbs, for each 12-month rolling period ending in the year covered by the Certification; and

iii) Emissions during QAMO hours, in lbs, and mercury content in the fuel fired in such EGU, in lbs, for each month in the year covered by the Certification and in the previous year.

C) If complying with this Subpart B by means of Section 225.230(b):

i) Emissions and allowable emissions during QAMO hours for each 12-month rolling period ending in the year covered by the Certification; and

ii) Emissions and allowable emissions during QAMO hours, and which standard of compliance the owner or operator was utilizing for each month in the year covered by the Certification and in the previous year.

D) If complying with this Subpart B by means of Section 225.230(d):

i) Emissions and allowable emissions during QAMO hours for all EGUs at the source for each 12-month rolling period ending in the year covered by the Certification; and

ii) Emissions and allowable emissions during QAMO hours, and which standard of compliance the owner or operator was utilizing for each month in the year covered by the Certification and in the previous year.

E) If complying with this Subpart B by means of Section 225.232:

i) Emissions and allowable emissions during QAMO hours for all EGUs at the source in an Averaging Demonstration for each 12-month rolling period ending in the year covered by the Certification; and

ii) Emissions and allowable emissions during QAMO hours, with the standard of compliance the owner or operator was utilizing for each EGU at the source in an Averaging Demonstration for each month for all EGUs at the source in an Averaging Demonstration in the year covered by the Certification and in the previous year.

F) Any deviations or exceptions each month and discussion of the reasons for such deviations or exceptions.

3) All Annual Certifications of Compliance required to be submitted must include the following certification by a responsible official:

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

4) The owner or operator of an EGU must submit its first Annual Certification of Compliance to address calendar year 2009 or the calendar year in which the EGU commences commercial operation, whichever is later. Notwithstanding subsection (d)(2) of this Section, in the Annual Certifications of Compliance that are required to be submitted by May 1, 2010, and May 1, 2011, to address calendar years 2009 and 2010, respectively, the owner or operator is not required to provide 12-month rolling data for any period that ends before June 30, 2010.

e) Deviation Reports. For each EGU, the owner or operator must promptly notify the Agency of deviations from requirements of this Subpart B. At a minimum, these notifications must include a description of such deviations within 30 days after discovery of the deviations, and a discussion of the possible cause of such deviations, any corrective actions, and any preventative measures taken.

f) Quality Assurance RATA Reports. The owner or operator of an EGU must submit to the Agency, Air Compliance and Enforcement Section, the quality assurance RATA report for each EGU or group of EGUs monitored at a common stack and each non-EGU pursuant to Section 1.16(b)(2)(B) of Appendix B to this Part, within 45 days after completing a quality assurance RATA.

(Source: Amended at 39 Ill. Reg. , effective)

Section 225.291 Combined Pollutant Standard: Purpose

The purpose of Sections 225.291 through 225.299 (hereinafter referred to as the Combined Pollutant Standard ("CPS")) is to allow an alternate means of compliance with the emissions standards for mercury in Section 225.230(a) for specified EGUs through permanent shut-down, installation of ACI, ~~and~~ the application of pollution control technology for NO_x, PM, and SO_2 emissions<u>, or the conversion of an EGU to a fuel other than coal (such as natural gas or distillate fuel oil with sulfur content no greater than 15 ppm),</u> that also reduce mercury emissions as a co-benefit and to establish permanent emissions standards for those specified EGUs. Unless otherwise provided for in the CPS, owners and operators of those specified EGUs are not excused from compliance with other applicable requirements of Subparts B, C, D, and E.

(Source: Amended at 39 Ill. Reg. , effective)

Section 225.292 Applicability of the Combined Pollutant Standard

a) As an alternative to compliance with the emissions standards of Section 225.230(a), the owner or operator of specified EGUs in the CPS located at <u>the</u> Fisk, Crawford, Joliet, Powerton, Waukegan, and Will County power plants may elect for all of those EGUs as a group to demonstrate compliance pursuant to the CPS, which establishes control requirements and emissions standards for NO_x, PM, SO_2, and mercury. For this purpose, ownership of a specified EGU is determined based on direct ownership, by holding a majority interest in a company that owns the EGU or EGUs, or by the common ownership of the company that owns the EGU, whether through a parent-subsidiary relationship, as a sister corporation, or as an affiliated corporation with the same parent corporation, provided that the owner or operator has the right or authority to submit a CAAPP application on behalf of the EGU.

b) A specified EGU is an~~a coal-fired~~ EGU listed in Appendix A, irrespective of any subsequent changes in ownership of the EGU or power plant, the operator, unit designation, or name of unit, or the type of fuel combusted (such as natural gas or distillate fuel oil with sulfur content no greater than 15 ppm).

c) The owner or operator of each of the specified EGUs electing to demonstrate compliance with Section 225.230(a) pursuant to the CPS must submit an application for a CAAPP permit modification to the Agency, as provided for in Section 225.220, that includes the information specified in Section 225.293 that clearly states the owner's or operator's election to demonstrate compliance with Section 225.230(a) pursuant to the CPS.

d) If an owner or operator of one or more specified EGUs elects to demonstrate compliance with Section 225.230(a) pursuant to the CPS, then all specified EGUs owned or operated in Illinois by the owner or operator as of December 31, 2006, as defined in subsection (a) of this Section, are thereafter subject to the standards and control requirements of the CPS. Such EGUs are referred to as a Combined Pollutant Standard (CPS) group.

e) If an EGU is subject to the requirements of this Section~~,~~ then the requirements apply to all owners and operators of the EGU.

(Source: Amended at 39 Ill. Reg. , effective)

Section 225.293 Combined Pollutant Standard: Notice of Intent

The owner or operator of one or more specified EGUs that intends to comply with Section 225.230(a) by means of the CPS must notify the Agency of its intention on or before December 31, 2007. The following information must accompany the notification:

a) The identification of each EGU that will be complying with Section 225.230(a) pursuant to the CPS, with evidence that the owner or operator has identified all specified EGUs that it owned or operated in Illinois as of December 31, 2006, and which commenced commercial operation on or before December 31, 2004;

b) If an EGU identified in subsection (a) of this Section is also owned or operated by a person different than the owner or operator submitting the notice of intent, a demonstration that the submitter has the right to commit the EGU or authorization from the responsible official for the EGU submitting the application; and

c) A summary of the current control devices installed and operating on each EGU and identification of the additional control devices that will likely be needed for each EGU to comply with emission control requirements of the CPS;~~.~~

d) Additionally, the owner or operator of a specified EGU that, on or after January 1, 2015, changes the type of primary fuel combusted by the unit or the control device(s) installed and operating on the unit must notify the Agency of such change by January 1, 2017, or within 30 days of the completion of such change, whichever is later.

(Source: Amended at 39 Ill. Reg. , effective)

Section 225.294 Combined Pollutant Standard: Control Technology Requirements and Emissions Standards for Mercury

a) Control Technology Requirements for Mercury.

1) For each coal-fired EGU in a CPS group other than an EGU that is addressed by subsection (b) of this Section, the owner or operator of the EGU must install, if not already installed, and properly operate and maintain, by the dates set forth in subsection (a)(2) of this Section, ACI equipment complying with subsections (g), (h), (i), (j), and (k) of this Section, as applicable.

2) By the following dates, for the EGUs listed in subsections (a)(2)(A) and (B), which include hot and cold side ESPs, the owner or operator must install, if not already installed, and begin operating ACI equipment or the Agency must be given written notice that the EGU will be shut down on or before the following dates:

A) Fisk 19, Crawford 7, Crawford 8, Waukegan 7, and Waukegan 8 on or before July 1, 2008; and

B) Powerton 5, Powerton 6, Will County 3, Will County 4, Joliet 6, Joliet 7, and Joliet 8 on or before July 1, 2009.

b) Notwithstanding subsection (a) of this Section~~,~~:

1) The~~the~~ following EGUs are not required to install ACI equipment because they will be permanently shut down, as addressed by Section 225.297, by the date specified:

A~~1~~) EGUs that are required to permanently shut down:

i~~A~~) On or before December 31, 2007, Waukegan 6; and

ii~~B~~) On or before December 31, 2010, Will County 1 and Will County 2.

B~~2~~) Any other specified EGU that is permanently shut down by December 31, 2010; and~~.~~

2) On and after the date an EGU permanently ceases combusting coal, it is not required to install, operate, or maintain ACI equipment.

c) Beginning on January 1, 2015, and continuing thereafter, and measured on a rolling 12-month basis (the initial period is January 1, 2015, through December 31, 2015, and, then, for every 12-month period thereafter), each specified EGU that has not permanently ceased combusting coal, except Will County 3, shall achieve one of the following emissions standards:

1) An emissions standard of 0.0080 lbs mercury/GWh gross electrical output; or

2) A minimum 90 percent reduction of input mercury.

d) On and after April 16, 2015, Will County 3 must not combust coal.~~Beginning on January 1, 2016, and continuing thereafter, Will County 3 shall achieve the mercury emissions standards of subsection (c) of this Section measured on a rolling 12-month basis (the initial period is January 1, 2016, through December 31, 2016, and, then, for every 12-month period thereafter).~~

e) Compliance with Emission Standards

1) At any time prior to the dates required for compliance in subsections (c) and (d) of this Section, the owner or operator of a specified EGU, upon notice to the Agency, may elect to comply with the emissions standards of subsection (c) of this Section measured on either:

A) a rolling 12-month basis;~~,~~ or~~;~~

B) a quarterly calendar basis pursuant to the emissions testing requirements in Section 225.239(a)(4), (c), (d), (e), (f), (g), (h), (i), and (j) of this Subpart until June 30, 2012.

2) Once an EGU is subject to the mercury emissions standards of subsection (c) of this Section, it shall not be subject to the requirements of subsections (g), (h), (i), (j) and (k) of this Section;~~.~~

3) On and after the date an EGU permanently ceases combusting coal, it shall not be subject to the requirements of subsections (g), (h), (i), (j) and (k) of this Section.

f) Compliance with the mercury emissions standards or reduction requirement of this Section must be calculated in accordance with Section 225.230(a) or (b), or Section 225.232 until December 31, 2013.

g) For each EGU for which injection of halogenated activated carbon is required by subsection (a)(1) of this Section, the owner or operator of the EGU must inject halogenated activated carbon in an optimum manner:

1) Except as provided in subsection (h) of this Section, optimum manner is defined as all of the following:

A) The use of an injection system for effective absorption of mercury, considering the configuration of the EGU and its ductwork;

B) The injection of halogenated activated carbon manufactured by Alstom, Norit, or Sorbent Technologies, Calgon Carbon's FLUEPAC CF Plus, or Calgon Carbon's FLUEPAC MC Plus, or the injection of any other halogenated activated carbon or sorbent that the owner or operator of the EGU has demonstrated to have similar or better effectiveness for control of mercury emissions; and

C) The injection of sorbent at the following minimum rates, as applicable:

i) For an EGU firing subbituminous coal, 5.0 lbs per million actual cubic feet or, for any cyclone-fired EGU that will install a scrubber and baghouse by December 31, 2012, and which already meets an emission rate of 0.020 lb mercury/GWh gross electrical output or at least 75 percent reduction of input mercury, 2.5 lbs per million actual cubic feet;

ii) For an EGU firing bituminous coal, 10.0 lbs per million actual cubic feet or, for any cyclone-fired EGU that will install a scrubber and baghouse by December 31, 2012, and which already meets an emission rate of 0.020 lb mercury/GWh gross electrical output or at least 75 percent reduction of input mercury, 5.0 lbs per million actual cubic feet;

iii~~)~~) For an EGU firing a blend of subbituminous and bituminous coal, a rate that is the weighted average of the rates specified in subsections~~)~~(g)(1)(C)(i) and (ii) based on the blend of coal being fired; or

iv) A rate or rates set lower by the Agency, in writing, than the rate specified in any of subsection (g)(1)(C)(i)(ii)(iii) of this Section on a unit-specific basis, provided that the owner or operator of the EGU has demonstrated that such rate or rates are needed so that carbon injection will not increase particulate matter emissions or opacity so as to threaten noncompliance with applicable requirements for particulate matter or opacity.

~~4~~2) For purposes of subsection (g)(1)(C) of this Section, the flue gas flow rate shall be the gas flow rate in the stack for all units except for those equipped with activated carbon injection prior to a hot-side electrostatic precipitator; for units equipped with activated carbon injection prior to a hot-side electrostatic precipitator, the flue gas flow rate shall be the gas flow rate at the inlet to the hot-side electrostatic precipitator, which shall be determined as the stack flow rate adjusted through the use of Charles' Law for the differences in gas temperatures in the stack and at the inlet to the electrostatic precipitator ($V_{esp} = V_{stack} \times T_{esp}/T_{stack}$, where V = gas flow rate in acf and T = gas temperature in Kelvin or Rankine).

h) The owner or operator of an EGU that seeks to operate an EGU with an activated carbon injection rate or rates that are set on a unit-specific basis pursuant to subsection (g)(1)(C)(iv) of this Section must submit an application to the Agency proposing such rate or rates, and must meet the requirements of subsections (h)(1) and (h)(2) of this Section, subject to the limitations of subsections (h)(3) and (h)(4) of this Section:

1) The application must be submitted as an application for a new or revised federally enforceable operation permit for the EGU, and it must include a summary of relevant mercury emissions data for the EGU, the unit-specific injection rate or rates that are proposed, and detailed information to support the proposed injection rate or rates;

2) This application must be submitted no later than the date that activated carbon must first be injected. For example, the owner or operator of an EGU that must inject activated carbon pursuant to subsection (a)(1) of this Section must apply for unit-specific injection rate or rates by July 1, 2008. Thereafter, the owner or operator may supplement its application;

3) Any decision of the Agency denying a permit or granting a permit with conditions that set a lower injection rate or rates may be appealed to the Board pursuant to Section 39 of the Act; and

4) The owner or operator of an EGU may operate at the injection rate or rates proposed in its application until a final decision is made on the application including a final decision on any appeal to the Board.

i) During any evaluation of the effectiveness of a listed sorbent, alternative sorbent, or other technique to control mercury emissions, the owner or operator of an EGU need not comply with the requirements of subsection (g) of this Section for any system needed to carry out the evaluation, as further provided as follows:

1) The owner or operator of the EGU must conduct the evaluation in accordance with a formal evaluation program submitted to the Agency at least 30 days prior to commencement of the evaluation;

2) The duration and scope of the evaluation may not exceed the duration and scope reasonably needed to complete the desired evaluation of the alternative control techniques, as initially addressed by the owner or operator in a support document submitted with the evaluation program;

3) The owner or operator of the EGU must submit a report to the Agency no later than 30 days after the conclusion of the evaluation that describes the evaluation conducted and which provides the results of the evaluation; and

4) If the evaluation of alternative control techniques shows less effective control of mercury emissions from the EGU than was achieved with the principal control techniques, the owner or operator of the EGU must resume use of the principal control techniques. If the evaluation of the alternative control technique shows comparable effectiveness to the principal control technique, the owner or operator of the EGU may either continue to use the alternative control technique in a manner that is at least as effective as the principal control technique or it may resume use of the principal control technique. If the evaluation of the alternative control technique shows more effective control of mercury emissions than the control technique, the owner or operator of the EGU must continue to use the alternative control technique in a manner that is more effective than the principal control technique, so long as it continues to be subject to this Section.

j) In addition to complying with the applicable recordkeeping and monitoring requirements in Sections 225.240 through 225.290, the owner or operator of an EGU that elects to comply with this Subpart B by means of Sections 225.291 through 225.299 must also comply with the following additional requirements:

1) For the first 36 months that injection of sorbent is required, it must maintain records of the usage of sorbent, the flue gas flow rate from the EGU (and, if the unit is equipped with activated carbon injection prior to a hot-side electrostatic precipitator, flue gas temperature at the inlet of the hot-side electrostatic precipitator and in the stack), and the sorbent feed rate, in pounds per million actual cubic feet of flue gas, on a weekly average;

2) After the first 36 months that injection of sorbent is required, it must monitor activated sorbent feed rate to the EGU, gas flow rate in the stack, and, if the unit is equipped with activated carbon injection prior to a hot-side electrostatic precipitator, flue gas temperature at the inlet of the hot-side electrostatic precipitator and in the stack. It must automatically record this data and the sorbent carbon feed rate, in pounds per million actual cubic feet of flue gas, on an hourly average; and

3) If a blend of bituminous and subbituminous coal is fired in the EGU, it must keep records of the amount of each type of coal burned and the required injection rate for injection of activated carbon on a weekly basis.

k) In addition to complying with the applicable reporting requirements in Sections 225.240 through 225.290, the owner or operator of an EGU that elects to comply with Section 225.230(a) by means of the CPS must also submit quarterly reports for the recordkeeping and monitoring conducted pursuant to subsection (j) of this Section.

l) Until June 30, 2012, as an alternative to the CEMS (or excepted monitoring system) monitoring, recordkeeping, and reporting requirements in Sections 225.240 through 225.290, the owner or operator of an EGU may elect to comply with the emissions testing, monitoring, recordkeeping, and reporting requirements in Section 225.239(c), (d), (e), (f)(1) and (2), (h)(2), (i)(3) and (4), and (j)(1).

m) Notwithstanding any other provision in this Subpart, the requirements in Sections 225.240 through 225.290 of this Subpart, and any other mercury-related monitoring, recordkeeping, notice, analysis, certification, and reporting requirements set forth in this Subpart, including in this CPS, will not apply to a specified EGU on and after the date the EGU permanently ceases combusting coal.

(Source: Amended at 39 Ill. Reg. ________, effective ________)

Section 225.295 Combined Pollutant Standard: Emissions Standards for NO_x and SO_2

a) Emissions Standards for NO_x and Reporting Requirements.

1) Beginning with calendar year 2012 and continuing in each calendar year thereafter, the CPS group, which includes all specified EGUs, regardless of the type of fuel combusted, that have not been permanently shut down by December 31 before the applicable calendar year, must comply with a CPS group average annual NO_x emissions rate of no more than 0.11 lbs/mmBtu.

2) Beginning with ozone season control period 2012 and continuing in each ozone season control period (May 1 through September 30) thereafter, the CPS group, which includes all specified EGUs, regardless of the type of fuel combusted, that have not been permanently shut down by December 31 before the applicable ozone season, must comply with a CPS group average ozone season NO_x emissions rate of no more than 0.11 lbs/mmBtu.

3) The owner or operator of the specified EGUs in the CPS group must file, not later than one year after startup of any selective SNCR on such EGU, a report with the Agency describing the NO_x emissions reductions that the SNCR has been able to achieve.

4) The specified EGUs are not subject to the requirements set forth in 35 Ill. Adm. Code 217, Subpart M, including without limitation the NO_x emission standards set forth in 35 Ill. Adm. Code 217.344.

b) Emissions Standards for SO_2. Beginning in calendar year 2013 and continuing in each calendar year thereafter, the CPS group must comply with the applicable CPS group average annual SO_2 emissions rate listed as follows. For purposes of subsections (b) and (d) only, the CPS group includes only those specified EGUs that combust coal:

year	lbs/mmBtu
2013	0.44
2014	0.41
2015	0.28
2016	0.195
2017	0.15
2018	0.13
2019	0.11

c) Compliance with the NO_x and SO_2 emissions standards must be demonstrated in accordance with Sections 225.310, 225.410, and 225.510. The owner or operator of the specified EGUs must complete the demonstration of compliance pursuant to Section 225.298(c) before March 1 of the following year for annual standards and before November 30 of the particular year for ozone season control periods

(May 1 through September 30) standards, by which date a compliance report must be submitted to the Agency.

d) The CPS group average annual SO_2 emission rate, annual NO_x emission rate and ozone season NO_x emission rates shall be determined as follows:

$$ER_{avg} = \sum_{i=1}^{n} (SO_{2i} \text{ or } NO_{xi} \cancel{\text{ tons}}) / \sum_{i=1}^{n} (HI_i)$$

Where:

ER_{avg} = average annual or ozone season emission rate in lbs/mmBbtu of all EGUs in the CPS group.

HI_{i}, = heat input for the annual or ozone control period of each EGU, in mmBtu.

SO_{2i} = actual annual SO_2 lbs~~tons~~ of each EGU in the CPS group, as set forth in subsection (b).

NO_{xi} = actual annual or ozone season NO_x lbs~~tons~~ of each EGU in the CPS group.

N = number of EGUs that are in the CPS group.

I = each EGU in the CPS group.

(Source: Amended at 39 Ill. Reg. , effective)

Section 225.296 Combined Pollutant Standard: Control Technology Requirements for NO_x, SO_2, and PM Emissions

a) Control Technology Requirements for NO_x and SO_2.

1) On or before December 31, 2013, the owner or operator must either permanently shut down or install and have operational FGD equipment on Waukegan 7;

2) On or before December 31, 2014, the owner or operator must either permanently shut down or install and have operational FGD equipment on Waukegan 8;

3) On or before December 31, 2015, the owner or operator must either permanently shut down or install and have operational FGD equipment on Fisk 19;

4) If Crawford 7 will be operated after December 31, 2018, and not permanently shut down by this date, the owner or operator must:

A) On or before December 31, 2015, install and have operational SNCR or equipment capable of delivering essentially equivalent NO_x reductions on Crawford 7; and

B) On or before December 31, 2018, install and have operational FGD equipment on Crawford 7;

5) If Crawford 8 will be operated after December 31, 2017 and not permanently shut down by this date, the owner or operator must:

A) On or before December 31, 2015, install and have operational SNCR or equipment capable of delivering essentially equivalent NO_x emissions reductions on Crawford 8; and

B) On or before December 31, 2017, install and have operational FGD equipment on Crawford 8.

b) Other Control Technology Requirements for SO_2. On and after April 16, 2015, Will County 3 must not combust coal. On and after December 31, 2016, Joliet 6, 7, and 8 must not combust coal. Owners or operators of the other specified EGUs must either permanently shut down, permanently cease combusting coal at, or install FGD equipment on each specified EGU (except Will County 4~~Joliet 5~~), on or before December 31, 2018, unless an earlier date is specified in subsection (a) of this Section.

c) Control Technology Requirements for PM. The owner or operator of the Waukegan 7 EGU~~two specified EGUs listed in this subsection~~ that is~~are~~ equipped with a hot-side ESP must replace the hot-side ESP with a cold-side ESP, install an appropriately designed fabric filter, or permanently shut down the EGU by December 31, 2014~~the dates specified~~. Hot-side ESP means an ESP on a coal-fired boiler that is installed before the boiler's air-preheater where the operating temperature is typically at least 550º F, as distinguished from a cold-side ESP that is installed after the air pre-heater where the operating temperature is typically no more than 350º F.

~~1) Waukegan 7 on or before December 31, 2013; and~~

~~2) Will County 3 on or before December 31, 2015.~~

d) Beginning on December 31, 2008, and annually thereafter up to and including December 31, 2015, the owner or operator of the Fisk power plant must submit in writing to the Agency a report on any technology or equipment designed to affect air quality that has been considered or explored for the Fisk power plant in the preceding 12 months. This report will not obligate the owner or operator to install any equipment described in the report.

e) Notwithstanding 35 Ill. Adm. Code 201.146(hhh), until an EGU has complied with the applicable requirements of subsections 225.296(a), (b), and (c), the owner or operator of the EGU must obtain a construction permit for any new or modified air pollution control equipment that it proposes to construct for control of emissions of mercury, NO_x, PM, or SO_2.

(Source: Amended at 39 Ill. Reg. , effective)

Section 225.298 Combined Pollutant Standard: Requirements for NO_x and SO_2 allowances

a) The following requirements apply to the owner and operator with respect to SO_2 and NO_x allowances, which mean, for the purposes of this Section 225.298, allowances necessary for compliance with Section 225.310, 225.410, or 225.510, 40 CFR 72, or ~~S~~subparts AA and AAAA of 40 CFR 96, or any future federal NO_x or SO_2 emissions trading programs that modify or replace these programs:

~~1) The owner or operator of specified EGUs in a CPS group is permitted to sell, trade, or transfer SO_2 and NO_x emissions allowances of any vintage owned, allocated to, or earned by the specified EGUs (the "CPS allowances") to its affiliated Homer City, Pennsylvania, generating station for as long as the Homer City Station needs the CPS allowances for compliance.~~

1~~2~~) ~~When and if the Homer City Station no longer requires all of the CPS allowances,~~ The~~the~~ owner or operator of specified EGUs in a CPS group may sell, trade, or transfer any and all SO_2 and NO_x emissions allowances of any vintage owned, allocated to, or earned by the specified EGUs (the “CPS allowances”)~~remaining CPS allowances~~, without restriction, to any person or entity located anywhere, except that the owner or operator may not directly sell, trade, or transfer CPS allowances to a unit located in Ohio, Indiana, Illinois, Wisconsin, Michigan, Kentucky, Missouri, Iowa, Minnesota, or Texas.

2~~3~~) In no event shall this subsection (a) require or be interpreted to require any restriction whatsoever on the sale, trade, or exchange of the CPS allowances by persons or entities who have acquired the CPS allowances from the owner or operator of specified EGUs in a CPS group.

b) The owner or operator of EGUs in a specified CPS group is prohibited from purchasing or using SO_2 and NO_x allowances for the purposes of meeting the SO_2 and NO_x emissions standards set forth in Section 225.295.

c) By March 1, 2010, and continuing each year thereafter, the owner or operator of the EGUs in a CPS group must submit a report to the Agency that demonstrates compliance with the requirements of this Section for the previous calendar year and ozone season control period (May 1 through September 30), and includes identification of any NO_x or SO_2 allowances that have been used for compliance with any NO_x or SO_2 trading programs, and any NO_x or SO_2 allowances that were sold, gifted, used, exchanged, or traded. A final report must be submitted to the Agency by August 31 of each year, providing either verification that the actions described in the initial report have taken place, or, if such actions have not taken place, an explanation of the changes that have occurred and the reasons for such changes.

(Source: Amended at 39 Ill. Reg. , effective)

225.APPENDIX A Specified EGUs for Purposes of the CPS (~~Midwest Generation's~~ Coal-Fired Boilers as of July 1, 2006)

Plant	Permit Number	Boiler	Permit designation	CPS Designation
Crawford	031600AIN	7	Unit 7 Boiler BLR1	Crawford 7
		8	Unit 8 Boiler BLR2	Crawford 8
Fisk	031600AMI	19	Unit 19 Boiler BLR19	Fisk 19
Joliet	197809AAO	71	Unit 7 Boiler BLR71	Joliet 7
		72	Unit 7 Boiler BLR72	Joliet 7
		81	Unit 8 Boiler BLR81	Joliet 8
		82	Unit 8 Boiler BLR82	Joliet 8
		5	Unit 6 Boiler BLR5	Joliet 6
Powerton	179801AAA	51	Unit 5 Boiler BLR 51	Powerton 5
		52	Unit 5 Boiler BLR 52	Powerton 5
		61	Unit 6 Boiler BLR 61	Powerton 6
		62	Unit 6 Boiler BLR 62	Powerton 6
Waukegan	097190AAC	17	Unit 6 Boiler BLR17	Waukegan 6
		7	Unit 7 Boiler BLR7	Waukegan 7
		8	Unit 8 Boiler BLR8	Waukegan 8
Will County	197810AAK	1	Unit 1 Boiler BLR1	Will County 1
		2	Unit 2 Boiler BLR2	Will County 2
		3	Unit 3 Boiler BLR3	Will County 3
		4	Unit 4 Boiler BLR4	Will County 4

(Source: Amended at 39 Ill. Reg. , effective)