ILLINOIS POLLUTION CONTROL BOARD
October 1, 2015

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

Proposed Rule. Second Notice.

OPINION AND ORDER OF THE BOARD (by J.A. Burke):

The Illinois Environmental Protection Agency (Agency) proposes to amend the Board's air pollution regulations to control sulfur dioxide (SO_2) emissions. The Agency's proposal intends to meet Illinois' obligations under the federal Clean Air Act and to satisfy Illinois' obligation to submit a state implementation plan (SIP) to the United States Environmental Protection Agency (USEPA) for approval with respect to the 2010 National Ambient Air Quality Standard (NAAQS) for SO_2. Two areas in Illinois have been designated as nonattainment for this NAAQS: Lemont (townships in Cook and Will Counties) and Pekin (townships in Tazewell and Peoria Counties).

The Agency sought expedited review of its proposal and the Board promptly issued the Agency's proposal for first notice publication on May 7, 2015. After conducting three hearings and reviewing comments received, the Board proposes amendments to Parts 214, 217, and 225 for second notice review by the Joint Committee on Administrative Rules (JCAR).

PROCEDURAL HISTORY

On April 28, 2015, the Agency filed a proposal to amend Parts 214, 217, and 225 of the Board's air pollution regulations to implement the 2010 NAAQS for $SO_{2.}$ The Agency filed its statement of reasons (SR), technical support document (TSD), proposed rule language, and other supporting documents. On April 30, 2015, the Agency filed a motion to amend the rulemaking proposal, which the Board granted. The motion included a list of approximately 725 entities titled "Illinois Sources Potentially Affected by Proposed Amendments to Liquid Fuel Rules" which the Agency intended to attach as Appendix A to the TSD.

On May 7, 2015, without substantive review, the Board issued the Agency's proposal, as amended, for first notice publication. The proposed regulations were published in the *Illinois Register* on May 22, 2015. 39 Ill. Reg. 7125 (May 22, 2015). Publication started a comment period of 45 days (5 ILCS 100/5-40(b) (2014)), which the Board extended until July 24, 2015. The Board received one comment on its first notice proposal, from the Agency, noting typographical errors in the proposal as it appeared at first notice publication. The Board also received questions from JCAR.

The hearing officer scheduled three hearings: July 8, 2015 in Springfield; July 29, 2015 in Joliet; and August 4, 2015 in Pekin. The Board received transcripts for each hearing as follows: the July 8, 2015 hearing transcript was received on July 9, 2015 (Tr. 1); the July 29, 2015 transcript was received on July 30, 2015 (Tr. 2); and the transcript for the August 4, 2015 hearing was received on August 6, 2015 (Tr. 3).

Prior to the first hearing, the Agency filed testimony for one witness, Rory Davis, an Environmental Protection Engineer in the Air Quality Planning Section of the Agency's Air Pollution Control Division. Mr. Davis appeared as a witness for the Agency at the hearing along with David Bloomberg, Manager of the Air Quality Planning Section, and Jeff Sprague, Modeling Unit Manager in the Air Quality Planning Section. Jackie Sims, Regulatory Unit Manager in the Air Quality Planning Section, also attended the hearing on behalf of the Agency. The Illinois Environmental Regulatory Group (IERG) filed questions for the hearing. The Agency responded to questions from IERG, and Midwest Generation, LLC. The Board also heard public comments at the first hearing.

The following exhibits were entered at the first hearing: Testimony of Rory Davis (Agency Exh. A); Illinois Environmental Protection Agency's Responses to IERG's Pre-Filed Questions (Agency Exh. B); and Illinois Environmental Protection Agency's Responses to Board's Pre-Filed Questions (Agency Exh. C).

Prior to the second hearing, IERG filed the testimony of David Kolaz, an environmental consultant, which was later amended. Sierra Club and the Environmental Law and Policy Center (ELPC) filed questions for the Agency. The Agency also filed comments following the first hearing on July 23, 2015 (PC 4). At hearing, the Agency again presented Mr. Bloomberg, Mr. Davis, and Mr. Sprague, who took questions from Sierra Club, as well as questions from IERG and Midwest Generation. The Agency further took questions from Citizens Against Ruining the Environment (CARE), and members of the public. IERG presented the testimony of Mr. Kolaz and made him available for questions, of which there were none. The Board also heard public comments.

The following exhibits were entered at the second hearing: Illinois Environmental Protection Agency's Responses to the Board's Second Set of Pre-Filed Questions (Agency Exh. D); Post-Hearing Comments of the Illinois Environmental Protection Agency (Agency Exh. E); and Amended Testimony of David Kolaz on behalf of IERG (IERG Exh. A).

Prior to the third hearing, Sierra Club and ELPC filed the testimonies of Ranajit Sahu, an engineer and air pollution consultant, and H. Andrew Gray, who is experienced in air quality research. At hearing, Mr. Sahu and Mr. Gray took questions from the Agency, IERG, and Midwest Generation. Mr. Bloomberg testified on behalf of the Agency and took questions from Sierra Club, Midwest Generation, and members of the public in attendance. Public commenters also spoke at the third hearing.

The following exhibits were entered at the third hearing: State Mandates Act Questionnaire 35 Ill. Adm. Code 214 (Agency Exh. F); State Mandates Act Questionnaire 35 Ill.

Adm. Code 217 (Agency Exh. G); Pre-Filed Testimony of Ranajit Sahu on behalf of Sierra Club and ELPC (Sierra Club Exh. A) (Sahu); Pre-Filed Testimony of H. Andrew Gray on behalf of Sierra Club and Environmental Law and Policy Center (Sierra Club Exh. B) (Gray); Lemont SO_2 Annual Averages 1983-2014 (Agency Exh. H); and Pekin SO_2 Annual Averages 1983-2014 (Agency Exh. I).

The Board issued three sets of Board questions for the Agency through hearing officer orders, and the Agency filed responses as follows: the first set of Board questions were issued on June 25, 2015, and the Agency filed its response on July 7, 2015 (Agency Ans. 1); the second set of Board questions were issued on July 16, 2015, and the Agency filed its response on July 23, 2015 (Agency Ans. 2); and the third set of Board questions were issued on August 3, 2015, which the Agency responded to on August 14, 2015 (Agency Ans. 3). In response to the Board's first set of questions, the Agency also filed a second motion to amend its rulemaking proposal on July 7, 2015 (Second Mot. Amend).

The hearing officer set final filing deadlines at the third hearing. On August 14, 2015, the Agency filed updated versions of Parts 214 and 225 to reflect changes to those parts throughout this rulemaking. Final comments, including public comments, were due by August 28, 2015. The Board received filings from individuals, as well as comments on behalf of CARE (PC 148), the Agency (PC 282), IERG (PC 281), Midwest Generation (PC 283), the Illinois Attorney General (PC 284), and the Sierra Club and the ELPC (PC 285). Responses to final comments were due by September 11, 2015. On that date, the Board received responses from Midwest Generation (PC 1448), the Illinois Attorney General (PC 1449), and the Agency (PC 1450).

REGULATORY BACKGROUND

Federal Clean Air Act

Under the federal Clean Air Act (42 U.S.C. § 7401 *et seq.*), USEPA sets nationwide air quality goals known as NAAQS. 42 U.S.C. § 7409. In 2010, USEPA set a new NAAQS for SO_2 replacing the prior standard. 75 Fed. Reg. 35520 (June 22, 2010). The 2010 standard is a one hour daily maximum concentration of 75 parts per billion SO_2 measured at an ambient air monitor and evaluated as a three-year average. *Id.*

Effective October 4, 2013, USEPA designated two areas in Illinois as not attaining the 2010 standard. 78 Fed. Reg. 47191, 47192 (Aug. 5, 2013). One area was identified as the Lemont nonattainment area and includes Lemont Township in Cook County and DuPage and Lockport Townships in Will County. 40 CFR 81.314. The second area was identified as the Pekin nonattainment area and includes Cincinnati and Pekin Townships in Tazewell County and Hollis Township in Peoria County. *Id.*

After USEPA sets a NAAQS, individual states must develop implementation plans to attain the NAAQS. 42 U.S.C. §§ 7410, 7514. In nonattainment areas, the Clean Air Act requires states to implement reasonably available control measures (RACM) including requiring existing sources to use reasonably available control technology (RACT). 42 U.S.C. § 7502(c)(1).

The Clean Air Act specifies deadlines for state plans. USEPA's designation of the Lemont and Pekin nonattainment areas was effective October 4, 2013. SR at 6. Illinois was required to submit its implementation plan within 18 months which was April 6, 2015. SR at 6; *see also* 42 U.S.C. § 7514(a). Illinois' implementation plan must provide for attainment of the 2010 standard in the Lemont and Pekin nonattainment areas within five years which is October 4, 2018. SR at 6; *see also* 42 U.S.C. § 7514a(a).

In May 2014, USEPA proposed a rule setting forth criteria for characterizing air quality. 79 Fed. Reg. 27446 (May 13, 2014). USEPA recently finalized this rule and it became effective on September 21, 2015. 80 Fed. Reg. 51052 (Aug. 21, 2015). The final rule directs states to provide data to USEPA characterizing air quality in areas with large sources (2000 tons per year or more) of SO_2 emissions. USEPA intends to use this data in future rounds of attainment designations for the 2010 NAAQS for SO_2.

Illinois Combined Pollutant Standard

In 2005, USEPA promulgated regulations requiring reduction of nitrogen oxides (NO_x), SO_2, and mercury emissions. 70 Fed. Reg. 25162 (May 12, 2005); 70 Fed. Reg. 28606 (May 18, 2005). The Agency proposed two rules to the Board to implement the federal rules. The first rulemaking was Proposed New 35 Ill. Adm. Code 225 Control of Emissions from Large Combustion Sources (Mercury), R06-25 (Dec. 21, 2006). This rule amended 35 Ill. Adm. Code Part 225 Subpart A and added Subpart B. The second rulemaking was Proposed New Clean Air Interstate Rule (CAIR) SO_2, NO_x Annual and NO_x Ozone Season Trading Programs, 35 Ill. Adm. Code 225, Subparts A, C, D, E, and F, R06-26 (Aug. 23, 2007). CAIR established a state-wide cap on SO_2 and NO_x emissions to be implemented through emission reductions or emission allowance trading.

In January 2007, the Agency and Midwest Generation filed joint comments in the CAIR rulemaking, proposing rules to control mercury, NO_x, and SO_2 as a new Subpart F to Part 225 known as the Combined Pollutant Standard (CPS). The CPS became effective on August 31, 2007. The Board subsequently moved the CPS from Subpart F of Part 225 to Subpart B of Part 225, Sections 225.291 through 225.299. Amendments to 35 Ill. Adm. Code 225: Control of Emissions from Large Combustion Sources (Mercury Monitoring), R09-10 (June 18, 2009).

The CPS provides alternate means to comply with mercury emissions standards by shutting down units and installing pollution control technology for NO_x, SO_2, and particulate matter emissions that also reduce mercury. 35 Ill. Adm. Code 225.291. Electric generating units at Midwest Generation's five power plants are subject to the CPS pursuant to Section 225.292 and an election made by Midwest Generation. The Midwest Generation electric generating units covered by the CPS are units 6, 7 and 8 at the Joliet Station (Joliet 6, 7, and 8); units 5 and 6 at the Powerton Station (Powerton 5 and 6); units 6, 7, and 8 at the Waukegan Station; units 1, 2, 3, and 4 at the Will County Station (Will County 1, 2, 3, and 4); unit 19 at the Fisk Station; and units 7 and 8 at the Crawford Station. 35 Ill. Adm. Code 225.Appendix A. Among other requirements in the CPS, electric generating units must comply with a group annual average SO_2 emission limit and NO_x emission limit. 35 Ill. Adm. Code 225.295(a) & (b).

On June 24, 2011, the Agency submitted portions of the CPS to USEPA for inclusion in the Illinois implementation plan addressing regional haze. 77 Fed. Reg. 3966 (Jan. 26, 2012). USEPA approved Illinois' submittal effective August 6, 2012. 77 Fed. Reg. 39943 (July 6, 2012).

Illinois NO_x RACT Rule

Part 217 of the Board's air pollution rules addresses NO_x emissions. In 2009, the Board adopted amendments to Part 217, known as the NO_x RACT Rule, to establish RACT requirements for NO_x emissions in nonattainment areas. In the Matter of: Nitrogen Oxides Emissions from Various Source Categories: Amendments to 35 Ill. Adm. Code Parts 211 and 217, R08-19 (Aug. 20, 2009). USEPA approved portions of these amendments as part of Illinois' implementation plan to satisfy USEPA's NO_x SIP Call Phase II. 74 Fed. Reg. 30466 (June 26, 2009).

AGENCY PROPOSAL

This rulemaking generally proposes to control SO_2 emissions to implement the 2010 NAAQS for SO_2. SR at 1. The Agency filed this rulemaking pursuant to Sections 4, 10, 27, 28, and 28.2 of the Environmental Protection Act (Act) (415 ILCS 5/4, 10, 27, 28, 28.2 (2014)) and Section 102.202 of the Board's procedural rules (35 Ill. Adm. Code 102.202). Most of the Agency's proposed revisions to Part 214 are to satisfy Illinois' obligation to submit a SIP to USEPA to address requirements under Sections 172, 191, and 192 of the Clean Air Act for the 2010 NAAQS for SO_2. SR at 6, citing 42 U.S.C. 7502, 7514, 7514a. The Agency states that it "has performed analyses including extensive computer modeling to ensure that the SIP . . . will result in attainment of the NAAQS in the affected areas." TSD at 4.

The Agency proposal includes other amendments that are not federally required but are intended "to aid Illinois' attainment planning efforts with respect to future rounds of attainment designations for the SO_2 NAAQS." SR at 1-2. The Agency further states that certain proposed provisions involve pollutants other than SO_2, but the Agency included these provisions because they relate to Illinois' attainment planning efforts for SO_2. SR at 2.

In sum, the Agency's proposal has three main outcomes: (1) establish SO_2 emission limits for specific sources; (2) establish sulfur content limits for liquid fuels used by fuel combustion emission units throughout the state; and (3) address the conversion of certain coal-fired electric generating units to fuel other than coal. SR at 2. The Agency's proposal also updates and corrects various existing regulations. *Id.*

Attainment with 2010 NAAQS for SO_2
(Part 214)

Source Specific Emission Limits

The Agency proposes to create new Subpart AA to Part 214 requiring eight particular sources to comply with SO_2 emission limits. SR at 7. The Agency conducted computer modeling to determine SO_2 emission reductions necessary to attain the 2010 NAAQS for SO_2. *Id.* The Agency proposes SO_2 emission limits for specific emission units at the affected sources based on the reductions needed for attainment with the NAAQS. *Id.* Some emission units will use a continuous emissions monitoring system or an alternative monitoring method to demonstrate compliance. *Id.* Other units may use either continuous monitoring or conduct performance testing. *Id.* at 8. Sources are required to comply with recordkeeping and reporting requirements. *Id*. Sources must comply with Subpart AA requirements by January 1, 2017. *Id.*

The eight stationary sources covered by proposed Subpart AA are:

Aventine Renewable Energy (Pekin)
Illinois Power Holdings E.D. Edwards (Bartonville)
Ingredion (Bedford Park)
Midwest Generation Joliet (Joliet)
Midwest Generation Powerton (Pekin)
Midwest Generation Will County (Romeoville)
Owens Corning (Summit)
Oxbow Midwest Calcining (Lemont)

The proposed SO_2 limits are hourly numeric limits on 36 emission units at these sources. Proposed Section 214.603. For one source, Midwest Generation's Powerton station, the Agency proposes compliance with the emission limit on a rolling 30-day average basis. *Id.* The Agency intends that the proposed limits will be adequate to attain the 2010 NAAQS for SO_2 in both the Lemont and Pekin nonattainment areas. TSD at 8. The Agency derived the proposed limits through "an iterative process that involved modeling allowable SO_2 emission rates at affected sources that reflected reasonable SO_2 control strategies at the various locations." *Id.* Units can achieve the hourly limits by using pollution control equipment, switching fuels, or operational changes. *Id.* at 8-9. For example, Joliet 6, 7, and 8, and Will County 3 will perform fuel conversion. Agency Ans. 1 at 5-6. Aventine Renewable Energy anticipates converting to natural gas combustion, and Owens Corning anticipates reconfiguring its operations. *Id.*

<u>Fuel Sulfur Content</u>

The Agency also proposes limits on sulfur content in fuel for all stationary sources burning diesel fuel in Illinois. Mot. Amend at 1. Specifically, units must comply with sulfur content limits of 1000 parts per million for residual fuel oil and 15 parts per million for distillate fuel oil, with certain exceptions. The Agency explains that distillate fuel is the most commonly used diesel fuel. TSD at 7, 13. Diesel fuel with sulfur content less than 15 parts per million is commonly referred to as ultra-low sulfur diesel. *Id.* The Agency asserts that fuel meeting these proposed limits is "widely available in the United States and Illinois." *Id.* Specifically regarding availability in Illinois, the Agency conferred with a number of fuel oil distributors and found that they only offered ultra-low sulfur diesel for sale. Agency Ans. 1 at 4. The Agency notes that federal rules now require nearly all vehicles to use ultra-low sulfur diesel. *Id.*

The Agency analyzed fuel use in Illinois and concluded that "the majority of commercial and industrial sources in Illinois" currently are using fuel compliant with the proposed limits. TSD at 19. The Agency reviewed fuel oil sales in Illinois from 2008 to 2013. *Id.* Ultra-low sulfur diesel constituted 25.4% of distillate fuel sales in 2006 and rose to 87.6% in 2011. *Id.* The Agency cited data from the United States Energy Information Administration, with the latest data being from 2013. Agency Ans. 1 at 3.

The Agency explains that it proposes sulfur content limits as a statewide measure because "they will aid in planning for possible additional future nonattainment designations" in Illinois. TSD at 7. The Agency will be conducting additional modeling during the next several years "that may result in additional areas being designated as nonattainment of the SO_2 NAAQS." *Id.* The Agency asserts that setting a statewide fuel standard "perhaps could aid in the prevention of an area or areas from being designated nonattainment." *Id.*

Owners or operators of subject emission units are required to maintain records demonstrating compliance. SR at 6-7. Most units must comply with fuel sulfur content requirements by January 1, 2017. *Id.* at 8. Some units have until January 1, 2019 to comply and one source is subject to a less stringent sulfur content limit as of January 1, 2016. *Id.* at fn. 2. The Agency asserts that these exceptions will not interfere with attainment of the 2010 NAAQS. *Id.*

The Agency identifies a list of potentially impacted sources in Appendix A to the TSD. This list contains approximately 725 sources. The Agency states that it conducted outreach with potentially affected sources, and representatives concurred that compliant fuels are widely available and an economically reasonable control measure. TSD at 7-8.

Units Subject to Combined Pollutant Standard (Parts 214, 217, 225)

Midwest Generation informed the Agency that it plans to convert electric generating units in the Lemont nonattainment area to use fuel other than coal such as natural gas or distillate fuel oil. SR at 9-10. Specifically, Midwest Generation intends to convert Joliet 6, 7, and 8 and Will County 3. SR at 10. The Agency proposes amendments, therefore, to address conversion of these units. SR at 11.

These four Midwest Generation units currently are subject to NO_x emission limits in the CPS in Part 225 and are exempt from NO_x emission limits in Part 217. SR at 10. Subpart M of Part 217, not part of the Illinois SIP, sets NO_x emission limits for electric generating units. 35 Ill. Adm. Code 217.Subpart M. Section 217.342(b), however, exempts certain units from complying with these limits if they instead comply with NO_x limits in Part 225. The proposal clarifies that the four converted units will remain subject to the CPS, including NO_x emission limits, regardless of the type of fuel combusted, and exempt from NO_x emission limits in Part 217. SR at 10.

The Agency proposes amendments to Parts 214 and 225 that require these four Midwest Generation units permanently to cease combusting coal. SR at 11. In Subpart AA of Part 214, the Agency proposes emission limits that reflect combustion of fuel other than coal. *Id.* In Part 225, the Agency proposes establishing deadlines after which these units are no longer allowed to combust coal. *Id.* The Agency proposes amending Part 225 to specify that units permanently ceasing combusting coal are no longer required to comply with mercury or particulate matter control technology requirements set forth in the CPS or mercury-related emission rates, monitoring, recordkeeping, notice, analysis, certification, or reporting requirements in the CPS. SR at 11-12. The Agency also proposes that units converting to fuel other than coal are not subject to the CPS group average annual SO_2 emission rate set forth in Section 225.295(b). SR at 12. These units will instead be subject to unit-specific SO_2 emission limits under the proposed Subpart AA in Part 214. *Id.*

Midwest Generation intends to continue combusting coal at Will County 4, and requested from the Agency that the unit be exempt from the requirement to shut down or install flue gas desulfurization (FGD) equipment by December 31, 2018, in lieu of a Joliet unit having such exemption. SR at 12. Midwest Generation also requested removing the provision of the CPS that allows the sale or trade of NO_x and SO_2 allowances to the Homer City, Pennsylvania generating station, due to a change in Midwest Generation's affiliation with the station. *Id.* at 12-13. The Agency proposes amendments implementing Midwest Generation's requests. *Id.* at 13.

State Implementation Plan Revisions

The Agency intends to submit to USEPA all revisions to Part 214 as part of Illinois' implementation plan for the 2010 NAAQS for SO_2. SR at 14. The Agency plans to submit to USEPA revisions to Sections 225.291, 225.292, 225.293, 225.295, and 225.296 (except 225.296(d)) of Part 225, and Appendix A to Part 225, as revisions to Illinois' implementation plan for regional haze. *Id.* at 15. The Agency expects to submit to USEPA revisions to Subpart Q of Part 217 as revisions to Illinois' implementation of the NO_x SIP Call Phase II SIP. *Id.*

Technical Feasibility and Economic Reasonableness

Proposed emission limits in Subpart AA "are available through a variety of SO_2 control measures, including fuel switching and the use of well-known desulfurization technologies such as wet and dry scrubbers and dry sorbent injection systems." SR at 17. The Agency states that fuel complying with its proposed fuel sulfur content limits "is already widely available in Illinois and is in fact already used by the majority of commercial and industrial sources in Illinois." *Id.* Every fuel oil distributor contacted by the Agency only offers ultra-low sulfur diesel due to federal requirements relating to motor vehicles. Agency Ans. 1 at 4. The Agency does not believe any price variability across Illinois would be different from that currently among dense urban areas and other areas of the State. *Id.*

The Agency states that the revisions to Subpart M of Part 217 and Part 225 only impact Midwest Generation, and that Midwest Generation agrees such revisions are both feasible and cost effective. SR at 17. The proposed revision to Subpart Q of Part 217 "imposes no additional requirements upon sources subject to Subpart Q" but is rather done for clarity. *Id.*

Outreach

The Agency met with individual sources impacted by the proposed Subpart AA and held informational meetings for source representatives and local chambers of commerce regarding the Agency's modeling efforts. SR at 18, Agency Ans. 1 at 18 (Q31). Draft amendments to Part 214 were provided to IERG, and the Agency also solicited comments in the August 2014 issue of the *Small Business Connection*, a publication provided to certain small businesses, chambers of commerce, business associations, trade groups, and legislators. SR at 18. The Agency later provided a draft of its proposed revisions to Parts 214, 217, and 225 to potentially impacted sources, public interest groups, and USEPA Region 5. *Id.* The Agency states that "at least five" of the recipients of the proposed Parts 214, 217, and 225 were from environmental organizations, including Sierra Club and ELPC. Agency Ans. 3 at 12 (Q69).

PUBLIC COMMENTS

The Board held three hearings in this rulemaking. The Board heard 35 comments from members of the public and various organizations. Additionally, the Board hearing officer received 137 written public comments at the August 4, 2015 public hearing in Pekin, which were filed with the Clerk of the Board as individual public comments. The deadline for filing of public comments was August 28, 2015. Including the comments received at the Pekin hearing, the Board received 1,450 written public comments, 60 of which were duplicates of previously filed comments.

Numerous individual commenters opposed the rule as being inadequate to protect the communities in the non-attainment areas. *See, e.g.*, PC 149. Individual commenters also opposed the proposed FGD exemption for Will County 4 and the proposed 30-day rolling average for Powerton. *Id.* Individual commenters requested a stronger emission limit at the E.D. Edwards facility. *Id.*

A number of facility employees attended the August 4, 2015 hearing in Pekin. Doug Vougvtas, speaking on behalf of the International Brotherhood of Electrical Workers Local 15, noted members at Powerton as well as their work with Will County, Joliet, and "pretty much all the generating stations across Illinois." Tr. 3 at 256. Mr. Vougvtas and two other facility employees who spoke at the hearing supported the Agency amendments as proposed. *Id.* at 258, 260.

Illinois Power Resources Generating, LLC (IPRG), owns and operates the E.D. Edwards facility. PC 280 at 1. IPRG states that the SO_2 emission limits for E.D. Edwards identified in proposed Section 214.603(b) are the result of a memorandum of agreement between IPRG and the Agency wherein IPRG agreed to a 92.2 percent reduction in the allowable SO_2 limits at the E.D. Edwards facility two years in advance of the 2017 deadline for implementation of emission reductions needed to demonstrate attainment with the 2010 NAAQS for SO_2. *Id.* IPRG states that this agreement has assisted the Agency in demonstrating attainment with the 2010 NAAQS for SO_2. *Id.* at 2. IPRG also requests that the Board update the Agency's proposal to reflect the direct owner and operator of the E.D. Edwards facility, by replacing "Illinois Power Holdings E.D. Edwards" with "Illinois Power Resources Generating E.D. Edwards." *Id.* Alternatively, IPRG asks the Board to replace "Illinois Power Holdings E.D. Edwards" with "IPH E.D. Edwards" to reflect the correct name of the company. *Id.* The Board changes the name of Illinois Power Holdings E.D. Edwards to Illinois Power Resources Generating E.D. Edwards at second notice.

The Board summarizes additional public comments in the discussion below.

BOARD DISCUSSION

Regulatory Authority

The Agency filed this proposal pursuant to Sections 4, 10, 27, 28, and 28.2 of the Environmental Protection Act (Act) (415 ILCS 5/13, 26 and 28 (2014)), and 35 Ill. Adm. Code 102.202. Section 27 of the Act requires that the Board take into account whether a proposed rule of general applicability is economically reasonable and technically feasible before adopting the rule. 415 ILCS 5/27(a) (2014).

Section 4 establishes the duties and authorities of the Agency. For example, Section 4(i) grants the Agency the authority to make recommendations to the Board for the adoption of regulations. 415 ILCS 5/4(i) (2014). Section 10 establishes the Board's regulatory authority, including granting the Board authority to adopt regulations to promote the purposes of the Act. 415 ILCS 5/10(A) (2014). Section 27 sets forth the Board's duties in adopting substantive regulations as described in the Act. 415 ILCS 5/27 (2014). Section 28 of the Act provides procedures the Board must follow in conducting a rulemaking proceeding. 415 ILCS 5/28 (2014). For example, Section 28(a) provides

> No substantive regulation shall be adopted, amended, or repealed until after a public hearing within the area of the State concerned. In the case of state-wide regulations hearings shall be held in at least two areas. . . . All such hearings shall be open to the public, and reasonable opportunity to be heard with respect to the subject of the hearing shall be afforded to any person. . . . After such hearing the Board may revise the proposed regulations before adoption in response to suggestions made at the hearing, without conducting a further hearing on the revisions. 415 ILCS 5/28(a) (2014).

Section 28.2 relates to rules that are needed to meet the requirements of, among others, the federal Clean Air Act. 415 ILCS 5/28.2 (2014). The Agency certifies that "the bulk of the proposed amendments to Part 214" are federally required. Agency's Certification of Required Rule at 1. When a rule is federally required, the Board must adopt a rule that (1) fully meets the applicable federal law; and (2) is "not inconsistent with any substantive environmental standard . . . within any Illinois statute." 415 ILCS 5/28.2(c) (2014). Further, the Board must consider all relevant evidence in the record when making this determination. *Id.*

Accordingly, the Board evaluates the Agency's proposal and all relevant evidence in the record to determine whether the rule fully meets the requirements of the Clean Air Act to control SO_2 emissions and is consistent with Illinois law. The Board also considers whether the rule is technically feasible and economically reasonable. As described below, the Board proposes for second notice review by JCAR amendments to the Board's air pollution regulations to control SO_2 emissions. The Board first addresses general issues and then turns to a section-by-section discussion.

<u>Attainment with 2010 NAAQS for SO_2</u>
<u>(Part 214)</u>

The Agency proposes revisions to Part 214 to control SO_2 emissions to attain the 2010 NAAQS for SO_2 in the Lemont and Pekin nonattainment areas. SR at 6. The Agency contends that its proposed restrictions on stationary sources and sulfur content in fuel are sufficient to demonstrate attainment with the 2010 NAAQS for SO_2. TSD at 4. The Agency conducted modeling to demonstrate that the amendments will result in attainment of the NAAQS. *Id.* The Agency also "included a margin of safety in its modeling approach by including intermittent sources, not mandated by USEPA's modeling guidance, and by including small sources." PC 282 at 35.

<u>Public Comments</u>

Sierra Club presents various arguments relating to the Agency's modeling of whether proposed changes to Part 214 are sufficient to demonstrate attainment with the 2010 NAAQS for SO_2. Sierra Club asks that the Board require the Agency to run more conservative attainment modeling and require additional emission reductions. PC 285 at 6-7.

First, Sierra Club argues that the Agency should have used a more conservative model to assess whether the proposed amendments to Part 214 will lead to attainment of the NAAQS. PC 285 at 1. Sierra Club contends that the Agency's modeling "hew[s] closely to the NAAQS 75 ppb limit" and fails to leave a "cushion" for events that may increase SO_2 emissions. *Id.* at 1-2. For example, Sierra Club is concerned that SO_2 sources in Lemont and Pekin may emit more than modeled allowable emissions during startup, shutdown, and malfunction. *Id.* at 2. Sierra Club further contends that a 99% or greater reduction in SO_2 cannot be achieved through a switch to ultra-low sulfur diesel because the actual reduction in SO_2 attributable to converting from 500 parts per million sulfur fuel to 15 parts per million sulfur fuel is a 97% reduction. *Id.* at 3. Sierra Club also argues that future small sources and flaring events are not adequately considered in the Agency's modeling. *Id.*

Second, Sierra Club contends that the Agency's modeling improperly included emissions not subject to unit specific limits in proposed Subpart AA. PC 285 at 19. Sierra Club argues that unit specific limits are needed to ensure that allowable emissions used in the modeling are enforceable. *Id.* In addition, Sierra Club contends that sulfur content limits for fuel are unenforceable and lead to fluctuations in emissions. Sahu at 6. Mr. Sahu states that sulfur content of fuel varies and that, because a facility does not test the vast majority of the fuel that it burns, fluctuations in emissions can easily exceed assumed limits. *Id.* Enforceability of the modeled emissions is also problematic because most of the sources without hourly emission limits do not appear to have continuous emission monitors. *Id.* at 8. Sierra Club further contends that the Agency provided no basis for its claim that these sources may be subject to enforceable permit limits. *Id.*

Third, Sierra Club argues that the Agency's attainment demonstration modeling should be made part of the record in this rulemaking. PC 285 at 7. An expert for Sierra Club, Mr. Gray, contends that the Agency's plan for controlling SO_2 emissions in the nonattainment areas is incomplete, as it is missing key elements required of a state implementation plan process. Gray at 1. Specifically, the plan does not include a documented modeling analysis. *Id.* at 1, 2. The Agency also does not clearly define baseline and controlled emission projections. *Id.* at 3. Mr. Gray also notes that the modeled emission rates were based on allowable emissions at many individual sources without explanation. *Id.* at 4. Mr. Gray concludes that these missing elements make it impossible to evaluate the model results and determine the adequacy of the proposal. *Id.*

Agency Response

The Agency states that it followed USEPA guidance in its modeling analysis and used conservative assumptions. TSD at 24. These conservative assumptions ensure that the NAAQS will be attained with an appropriate margin of safety. *Id.* The Agency explained how it conducted modeling, including inputs and methodology, as well as summaries of the modeling results for the Lemont and Pekin nonattainment areas. *Id.* at 24-31. The Agency notes that its modeling represents approximately 18 months of analysis. PC 282 at 18. The Agency further notes that it has "submitted numerous such modeling-based attainment demonstrations to the USEPA in the past, and cannot recall any instance when such a demonstration was rejected as inaccurate or unsupported." *Id.*

The Agency also addressed Sierra Club's criticisms. The Agency's modeling did not account for SO_2 exceedances due to startup, shutdown or malfunction events because attainment demonstrations "reflect source impacts with allowable emission rates at design or actual capacity and assuming continuous operation." Tr. 2 at 28, citing 40 CFR Part 51, Appendix W. The Agency also disagrees that fluctuations in sulfur content of fuel would lead to SO_2 emissions exceeding limits. *Id.* at 45, 62. Refineries are required under state and federal law to limit sulfur content to less than 15 parts per million for ultra-low sulfur diesel. PC 282 at 12. This is the same limit proposed by the Agency in this rulemaking. The Agency also notes that, while there may be variation in the sulfur content of ultra-low sulfur diesel fuel, fluctuations are toward lower sulfur content because refineries are conservative in ensuring that ultra-low sulfur diesel is well below the 15 parts per million limit. *Id.*

The Agency modeled all sources in the Lemont nonattainment area surrounding the violating monitor to determine which sources were significantly impacting nonattainment. PC 282 at 16. The Agency explains that it did not include every modeled source in its proposed rule because emission reductions were not needed at every modeled source to demonstrate attainment. *Id.* Further, modeled sources which are not significant contributors to nonattainment are still subject to enforceable limits through existing regulations or permit conditions. *Id.* at 16-17. Illinois sources included in the modeling but not specifically listed in the proposed regulations already have enforceable limits elsewhere in the regulations or enforceable permit conditions. Tr. 2 at 61. The Agency also stated it is unable to include in the rule emission limits for all of the larger sources modeled in the Lemont nonattainment area because many of the units are located in Indiana, where Illinois agencies cannot regulate them. *Id.* at 60-61.

The Agency responds to Mr. Gray's concerns relating to needing a detailed explanation of the implementation plan Illinois intends to submit to USEPA by explaining that these concerns are more appropriate in the later attainment demonstration presented to USEPA. Tr. 2 at 64-65. The Agency states that there will be public notice and 30-day public comment period when the Agency submits the SIP to USEPA. Further, if requested, there will be a separate hearing to discuss the attainment demonstration. *Id.* at 65.

Board Finding

The Agency conducted modeling of the Lemont and Pekin nonattainment areas to evaluate necessary emission limits and demonstrate attainment of the 2010 NAAQS for SO_2 using these emission limits. TSD at 24. The Agency states that it followed USEPA guidance in its modeling analysis. *Id*. For example, the Agency performed modeling using the AMS/EPA Regulatory Model (AERMOD). *Id*. AERMOD is USEPA's preferred model under 40 CFR Part 51, Appendix W for modeling to support the NAAQS for SO_2. 75 Fed. Reg. 35560 (June 22, 2010). The Agency also used nonattainment area receptors developed from communications with USEPA and considered acceptable to USEPA for permitting and attainment demonstrations. TSD at 25-26. Further, the Agency provides many examples of conservative assumptions in its modeling approach. *Id.* at 24.

In its proposal, the Agency provides a detailed description of the modeling performed. TSD at 24-31. The Agency evaluated receptors with design values exceeding the NAAQS. *Id.* at 26. The Agency analyzed which sources were primary contributors to the violating receptors. *Id.* The Agency evaluated reductions in allowable emissions at these sources and modeled these reductions to determine whether such emission rates would achieve attainment of the NAAQS. *Id.* The Agency's extensive modeling analysis shows that the proposed rules will attain the 2010 NAAQS for SO_2 in the Lemont and Pekin nonattainment areas. *Id.* at 4.

Sierra Club has not shown that the Agency's modeling is inconsistent with what is required by USEPA. Sierra Club further has not shown that the proposal is insufficient to reach attainment. Rather, Sierra Club raises concerns as to whether there is enough of a margin of safety in the modeling to account for a variety of scenarios that may increase SO_2 emissions. However, the Agency explains that the modeling approach for attainment demonstrations "ensures that the NAAQS will be attained at all points within the modeling domain, with an appropriate margin of safety . . . ." TSD at 24-25. The Agency added,

> [t]here is an inherent margin of safety built into the 1-hour SO_2 standard by USEPA. Additionally, the Agency included a margin of safety in its modeling approach by including intermittent sources, which USEPA's modeling guidance excluded, and by including small sources, whether or not they cause a 'significant concentration gradient' under federal regulations governing modeling." Agency Ans. 2 at 15 (Q56c).

Further, the Agency explained that after these rules are final, it will submit the rules to USEPA for USEPA approval and inclusion in the Illinois implementation plan. The submittal will include the Agency's modeling showing attainment of the NAAQS.

The Agency's modeling analysis shows that the proposed rules will result in attainment of the 2010 NAAQS for SO_2 in the Lemont and Pekin nonattainment areas by the October 4, 2018 deadline. The rulemaking record shows that the Agency's modeling method follows USEPA guidance and is sufficient to support the current rulemaking proposal at this point in the implementation process, and the proposed amendments provide an appropriate margin of safety. Further, the Board notes that the Agency provided detailed descriptions of the modeling analysis, answered questions presented by the Board, answered questions at hearing, and provided modeling documents for the record including a flash drive containing modeling data. The Board finds that modeling performed by the Agency is appropriate and supportive of the proposal.

The record shows that the proposal is designed to attain the 2010 NAAQS for SO_2 for the Lemont and Pekin nonattainment areas. Therefore, the Board finds that the record supports adopting the proposal, and that no additional modeling is needed at this time.

Units Subject to Combined Pollutant Standard
(Parts 214, 217, 225)

The Agency's proposal requires Midwest Generation to convert four of its electric generating units subject to the CPS to use fuel other than coal such as natural gas or distillate fuel oil. Specifically, Midwest Generation will cease using coal at Joliet 6, 7, and 8 and Will County 3. The Agency proposes amendments to Parts 214, 217, and 225 to address conversion of these units. SR at 11.

The Agency proposes amendments to Parts 214 and 225 that require the four Midwest Generation units permanently to cease combusting coal. SR at 11. In Subpart AA of Part 214, the Agency proposes emission limits that reflect combustion of fuel other than coal. *Id.* In Part 225, the Agency proposes establishing deadlines after which these units are no longer allowed to combust coal. *Id.* In addition, these four Midwest Generation units currently are subject to NO_x emission limits in the CPS in Part 225 and are exempt from NO_x emission limits in Part 217. SR at 10. The proposal clarifies that Midwest Generation's units will remain subject to the CPS, including NO_x emission limits, regardless of the type of fuel. *Id.*

Midwest Generation intends to continue burning coal at Will County 4, and requested that the unit be exempt from the requirement in 35 Ill. Adm. Code Section 225.296(b) to install FGD equipment in lieu of the Joliet unit having the exemption. SR at 12. This exemption is discussed under the section-by-section analysis of this opinion.

Public Comments

The People argue that the changes to Parts 217 and 225 should not be included in this proceeding to implement the 2010 NAAQS for SO_2. PC 284 at 4. The People contend that

Midwest Generation's conversion is the result of "shifts in energy economics [that] led Midwest Generation to a business decision . . . to increase the company's profits after careful consideration and analysis." *Id.* at 2. The People argue that changes to Parts 217 and 225 are unnecessary to implement the 2010 NAAQS for SO_2. *Id.* at 4. The People further argue that Midwest Generation is seeking to never be required to install FGD equipment on Will County 4. *Id.* at 7. The People liken this request to seeking a "variance-for-life," which is inconsistent with the Act and is "procedurally improper" in this proceeding. PC 1449 at 5, 6, citing <u>Monsanto Co. v. Pol. Control Bd.</u>, 67 Ill. 2d 276,286 (1977). The People assert that residents who breathe pollution from Will County 4 deserve to have a full and fair consideration of changing that unit's requirements under the CPS. PC 284 at 7. The People therefore conclude that the changes to Parts 217 and 225 should be removed from the proposed rule. *Id.*

CARE expresses similar objections and argues that the Agency's proposed relief for Midwest Generation is premature. PC 148 at 11. CARE states that the need for relief is still more than three years away and that requiring Midwest Generation "to adhere to the regulatory relief provisions provided by Illinois law is not prejudicial." *Id.* CARE states that Will County 4, in the meantime, "can continue to operate under the same regulatory regime the Agency now proposes, that is, in the context of a fleet wide SO_2 average." *Id.*

Midwest Generation argues that the CPS must be revised to convert from coal combustion as a means to comply with the CPS. PC 283 at 25-26. Part 225 changes are also necessary to clarify the applicable NO_x rate following conversion, whether converted units are subject to the SO_2 system rate, and inapplicability of mercury requirements to units that no longer emit mercury. *Id.* at 27. Midwest Generation states that it would not proceed with conversions if doing so still required the installation of FGD equipment. PC 1448 at 10.

<u>Agency Response</u>

The Agency states that its proposed amendments to Parts 217 and 225 are inextricably linked to its proposed amendments to Part 214. Agency Ans. 3 at 6 (Q63). For example, the Agency's proposed emission limits for Will County 3 and Joliet 6, 7, and 8 are in Section 214.603, but the requirement that these units cease burning coal is in Part 225. *Id.*

The Agency goes on to state that if the proposed changes to Part 225 were not included in the rulemaking, the proposed limitations in Part 214 would need to be amended since they are driven by modeling, reflecting the combustion of fuel other than coal. The Agency explains that it must use maximum allowable emissions in the modeling for the SIP attainment demonstration based on federal regulations at 40 CFR 51.Appendix W.Table 8-1. SR at 11; Agency Ans. 2 at 16. Absent the proposed revisions to Part 225, the Agency would have no ability to enforce the fuel conversions of the Will County 4 and Joliet units, and the Part 214 modeling-driven limitations would need to be amended, reflecting these units as they currently exist, with maximum allowable emissions based on the combustion of coal. PC 1450 at 3-5. As such, the Agency states that amended limitations under Part 214 for these units "would likely have been much higher (much less stringent) than the limits currently proposed by the Agency". *Id.* at 3. Consequently, the amended limitations could require reductions from other sources not currently involved in these proceedings in order to offset the reductions Midwest Generation offered. *Id.* at 4.

The Agency also asserts that the deadlines to cease combusting coal in Part 225 are essential to its proposal because without these enforceable deadlines the Agency would not have included limits in Part 214 reflecting combustion of natural gas or diesel. PC 1450 at 3. In addition, for units no longer combusting coal, the proposed revisions to Parts 217 and 225 are required to clarify mercury-related requirements and that such units remain subject to NO_x limits in the CPS. Agency Ans. 3 at 6 (Q63), PC 1450 at 5.

<u>Board Finding</u>

Under the current CPS requirements, Midwest Generation units are required to meet annual emission standards for SO_2. 35 Ill. Adm. Code 225.295(b). The SO_2 group rate starting in 2019 is the most stringent rate at 0.11 lb/mmBtu. 35 Ill. Adm. Code 225.295(b). Under the proposal, the anticipated SO_2 emission rates for the Joliet units are 0.0006 lb/mmBtu and 0.0015 lb/mmBtu for Will County 3 not burning coal. TSD at 17. The very low SO_2 emission rates for the four units correspond to the change in fuel from coal and are orders of magnitude smaller than the CPS rate. Agency Ans. 2 at 3 (Q43).

The Agency predicts that ending the use of coal in the Joliet units and Will County 3 will provide significant reductions of SO_2 emissions, as well as carbon dioxide, particulate matter and NO_x. TSD at 10. For example, ceasing coal combustion at these four units will result in 6000 tons of SO_2 reductions in 2017 as compared to the restrictions under the CPS, and more than 4500 tons annually in 2019 and thereafter. *Id.* at 17, Table 4. The proposed amendments will further reduce emissions of NO_x by 3000 tons, carbon dioxide by 7.5 million tons, particulate matter by 1900 tons, and mercury by 400 pounds per year. Agency Ans. 3 at 8 (Q64).

The Agency predicts that annual SO_2 emissions at the Will County station overall will decrease as compared to emissions under the current CPS due to the proposed prohibition on burning coal in Will County 3. The Agency projects that SO_2 emissions from Will County 3 will decrease from 3144 tons in 2014 to 13 tons in 2017 assuming that the unit burns ultra-low sulfur diesel less than 15 parts per million sulfur content. TSD at 16-17, Table 4; Agency Ans. 2 at 3 (Q43). The Agency calculates that Will County 3 and 4 together will emit 2261 tons in 2017 under the proposed rules as compared to 3515 tons under the CPS. TSD at 17, Table 4. The Agency's proposal, therefore, results in an overall reduction in annual SO_2 emissions at the Will County station.

Under the Agency's proposal, units continuing to burn coal, namely Will County 4 and units at Powerton station and Waukegan station, will continue to be subject to the CPS annual SO_2 emission rate. 35 Ill. Adm. Code 225.295(b) requires units in Midwest Generation's CPS group to meet a group-wide average limit for SO_2 emissions. These emission rates are 0.15 lb/mmBtu in 2017, 0.13 lb/mmBtu in 2018, and 0.11 lb/mmBtu in 2019. 35 Ill. Adm. Code 225.295(b). The Agency proposes that the units converting to fuel other than coal will no longer be subject to the CPS group average annual SO_2 emission rate. SR at 12. This is because, were the units to remain a part of the CPS group-wide average, they would be "essentially emitting no SO_2" and "it would lead to the coal-fired units possibly being able to emit greater amounts of SO_2 and offsetting the benefits of the natural gas units." Agency Ans. 2 at 18 (Q59a). Removing the four converted units from Midwest Generation's CPS group will therefore make the CPS annual SO_2 emission rate more stringent for the units that remain than if the converted units remained in the CPS.

The Agency strongly supports the conversion of the four units from coal combustion because the conversion will significantly reduce SO_2 emissions in the Lemont nonattainment area. TSD at 10. These reductions will aid the Agency's efforts to demonstrate attainment of the 2010 NAAQS for SO_2. *Id.* The emission reductions will further aid state planning efforts addressing regional haze, interstate transport, and the control of greenhouse gases from the power sector. *Id.* The Agency also notes that Midwest Generation projects the converted units will only operate at approximately 10% capacity, resulting in a heat input reduction that will reduce total NO_x tonnage emissions from the CPS units by more than 3,000 tons (23% from the group statewide). *Id.* at 11.

The Board agrees that the Agency's proposal will result in greater SO_2 reductions across the Midwest Generation CPS group than under the current CPS. The proposal also results in emission reductions for $NO_{x,}$ carbon dioxide, particulate matter, and mercury. The proposal makes no change to the numeric annual SO_2 emission rate in covering Midwest Generation's CPS group.

Addressing the procedural objections, the Board finds it appropriate that the Agency chose to propose amendments to Parts 217 and 225 together with Part 214 changes. USEPA's Guidance for 1-Hour SO_2 Nonattainment Area SIP Submissions (2014 Guidance) (found in the record at Agency Ans. 2, Exh. A) states, "[t]he control measures and associated SO_2 emissions limits for a specific facility would need to be permanent and enforceable under the SIP . . . ." 214 Guidance at 19. Conversions from coal combustion at Midwest Generation's Will County 3 and Joliet facilities impact the Agency's attainment modeling demonstration and proposed limitations in Part 214. Adopting the proposed SO_2 emission limits in Part 214 that were based on the cessation of coal at these units without the accompanying revisions to Part 225 would create no permanent and enforceable means to require these units cease combusting coal. Without Part 225's amendments, the currently proposed limitations in Part 214 would not be consistent with the 2014 Guidance and federal regulations at 40 CFR 51.Appendix W.Table 8-1 that require maximum allowable emissions in the modeling based on the units as they currently exist with the ability to combust coal. Also, without the amendments to Parts 217 and 225, the proposal would lack clarity regarding the applicability of mercury-related requirements and NO_x limitations in the CPS for units that may no longer combust coal.

Furthermore, once proposed, it is the Board's responsibility to analyze the rulemaking proposal within the parameters set forth in the Act. Parts 217 and 225, as well as Part 214, are duly promulgated Board regulations and the Act contemplates that amendments to Board regulations likewise be made through the rulemaking process. The Board finds nothing in the Agency's proposal to be procedurally improper or procedurally inconsistent with the Act. Opponents present no legal reason as to why the Agency cannot present the proposed amendments to Parts 217 and 225 as part of this rulemaking. The Board therefore proceeds to second notice on proposed amendments to Parts 214, 217, and 225.

SECTION BY SECTION ANALYSIS

Part 214 Sulfur Limitations
Subpart A General Provisions

Section 214.101 Measurement Methods

The Agency proposes to amend subsection (a) to add that sources may measure SO_2 emissions using a continuous emissions monitoring system. The Agency proposes to allow sources to measure sulfuric acid mist and sulfur trioxide by controlled condensate method approved by the Agency. The Board proposed these changes at first notice publication and proposes these changes at second notice. Additionally, the Board removes the unnecessary citation to Ill. Rev. Stat. 1989, ch. 111 1/2, par. 1010. The Board also corrects two errors at first notice. In Section 214.101(a), the Board replaces "Section 214.10(e)" with "Section 214.104(e)." In Section 214.101(b), the Board replaces "incoporated" with "incorporated."

Section 214.102 Abbreviations and Units

The Agency proposes correcting and updating abbreviations used in Part 214. The Board proposed these changes at first notice. In response to Board questions, the Agency proposes removing the reference to "60 F" as it is unnecessary because the definition of "btu" in Section 211 is adequate to define the term. Second Mot. Amend at 1. The Board proposes this change at second notice. The Board also replaces "BTU or" with "Btu or" in Section 214.102(a).

Section 214.104 Incorporations by Reference

The Agency proposes to add test methods found in 40 CFR 60 Appendix A, 40 CFR 75, and a USEPA guideline titled "USEPA's Emission Measurement Center Guideline Document (GD-042), Preparation and Review of Site-Specific Emission Test Plans, Revised March 1999." The Board proposed these changes at first notice publication and proposes these changes at second notice.

Part 214 Sulfur Limitations
Subpart B New Fuel Combustion Emission Sources

Section 214.121 Large Sources

Section 214.121 applies to certain fuel combustion sources with actual heat input greater than 73.2 MW (250 mmBtu/hr). The Agency proposes that the current regulation limiting SO_2 emissions when using residual fuel oil or distillate fuel oil applies prior to January 1, 2017. The Agency proposes that starting on January 1, 2017 sulfur content of all residual fuel oil must not exceed 1000 parts per million and sulfur content of all distillate fuel oil must not exceed 15 parts per million. The owner or operator of subject units must maintain records from the fuel supplier providing the sulfur content of fuel and method used to determine sulfur content. The owner or operator must retain the records for five years and provide copies to the Agency upon request.

The owner or operator must notify the Agency of any deviations from the sulfur content requirements. The Board proposed these changes at first notice publication.

In response to comments, the Agency also proposes amending Section 214.121(b)(2)(C)(i) to clarify that sources have flexibility regarding the types of records they must maintain to demonstrate compliance with the fuel sulfur content limits set forth in the proposal. Second Mot. Amend at 1. The Board proposes this additional change at second notice. The Board also makes two corrections. In Section 214.121(b)(2)(C)(i), the Board replaces "indicting" with "indicating." In Section 214.121(b)(2)(C)(iii), the Board replaces "an preventative measures taken" with "any preventative measures taken."

Section 214.122 Small Sources

Section 214.122 applies to certain fuel combustion sources with actual heat input of 73.2 MW (250 mmBtu/hr) or smaller. The Agency proposes that the current regulation limiting SO_2 emissions when using residual fuel oil or distillate fuel oil applies prior to January 1, 2017. The Agency proposes that starting on January 1, 2017 sulfur content of all residual fuel oil must not exceed 1000 parts per million and sulfur content of all distillate fuel oil must not exceed 15 parts per million. The owner or operator of subject units must maintain records from the fuel supplier providing the sulfur content of fuel and method used to determine sulfur content. The owner or operator must retain the records for five years and provide copies to the Agency upon request. The owner or operator must notify the Agency of any deviations from the sulfur content requirements. The Board proposed these changes at first notice publication.

In response to comments, the Agency also proposes amending Section 214.122(b)(2)(C)(i) to clarify that sources have flexibility regarding the types of records they must maintain to demonstrate compliance with the fuel sulfur content limits set forth in the proposal. Second Mot. Amend at 1. The Agency also noted that its proposed replacement of the period at the end of subsection 214.122(b)(1)(B) with a semicolon was left out of the Board's first notice. The Board proposes these additional changes at second notice.

Part 214 Sulfur Limitations
Subpart D Existing Liquid or Mixed Fuel Combustion Emission Sources

Section 214.161 Liquid Fuel Burned Exclusively

The Agency proposes that the current regulation limiting SO_2 emissions when using residual fuel oil or distillate fuel oil applies prior to January 1, 2017. The Agency proposes that starting on January 1, 2017 sulfur content of all residual fuel oil must not exceed 1000 parts per million and sulfur content of all distillate fuel oil must not exceed 15 parts per million. The owner or operator of subject units must maintain records from the fuel supplier providing the sulfur content of fuel and method used to determine sulfur content. The owner or operator must retain the records for five years and provide copies to the Agency upon request. The owner or operator must notify the Agency of any deviations from the sulfur content requirements.

The Agency proposes site-specific exceptions. Subsection (c) provides an exception for the electric generating units at Midwest Generation's Joliet, Powerton, Waukegan, and Will County stations. The sulfur content for distillate fuel oil must not exceed 500 parts per million in 2017 and 2018. Subsection (d) provides an exception for a Caterpillar Inc. facility in Montgomery. The sulfur content for distillate fuel oil must not exceed 500 parts per million. These exceptions allow these sources to use existing stocks of noncompliant fuel. TSD at 8. The Board proposed these changes at first notice publication.

In response to comments, the Agency also proposes amending Sections 214.161(b)(3)(A), 214.161(c)(4)(A), 214.161(c)(4)(B), 214.161(c)(4)(C), 214.161(d)(2)(A), and 214.161(d)(2)(B) to clarify that sources have flexibility regarding the types of records they must maintain to demonstrate compliance with the fuel sulfur content limitations set forth in the proposal. Second Mot. Amend at 1. The Board proposes these additional changes at second notice. The Board also makes three corrections. In Section 214.161(b), the Board replaces "subsections (c), (d), and €" with "subsections (c) and (d)." In Sections 214.161(b)(1) and (b)(2), the Board replaces "fu el" with "fuel." Following Section 214.161(c)(4)(E), the Board deletes the inadvertently repeated subsections (1), (2), and (3).

Section 214.162 Combination of Fuels

The Agency proposes to update variables used in the equation to calculate SO_2 emission rate when burning a combination of fuels. The Board proposed these changes at first notice. In response to Board questions, the Agency further proposes amending this section to correct an error in the metric version of the proposed limit. Second Mot. Amend at 10. The Board proposes this amendment at second notice.

Part 214 Sulfur Limitations
Subpart F Alternative Standards for Sources Inside Metropolitan Areas

Section 214.201 Alternative Standards for Sources in Metropolitan Areas

The Agency proposes to add a sentence clarifying that nothing in Section 214.201 excuses a source from complying with Subpart AA. The Board proposed these changes at first notice publication. In response to Board questions, the Agency agreed that the wording of Section 214.201(c) was unclear, and proposed clarifying amendments that the Board proposes at second notice. Agency Ans. 1 at 19 (Q35).

Part 214 Sulfur Limitations
Subpart K Process Emission Sources

Section 214.300 Scope

The Agency proposes to add language to impose fuel sulfur content limits upon all stationary sources burning diesel fuel in Illinois. Mot. Amend at 1. The Agency proposes amending this section to specify that the proposed fuel sulfur content limits also apply to process emission sources. The Board proposed these changes at first notice publication. At second notice, the Board removes the reference to "Subparts N et seq.", as there is no Subpart N.

Section 214.301 General Limitation

The Agency proposes to add a phrase clarifying that the limit on SO_2 emissions from process emission sources is on a dry basis when averaged over a one hour period. The Board proposed these changes at first notice publication. However, following concerns raised by IERG and discussions with industry representatives, the Agency requested withdrawal of its proposed amendment to this section. Agency Post-Hearing Comment at 76-7. The Agency states that these amendments are not required for Illinois' implementation plan submittal to USEPA. *Id.* at 6. The Board withdraws the amendments to this section at second notice.

Section 214.305 Fuel Sulfur Content Limitations

The Agency proposes that starting on January 1, 2017, for process emission sources, sulfur content of all residual fuel oil must not exceed 1000 parts per million and sulfur content of all distillate fuel oil must not exceed 15 parts per million. The owner or operator of subject units must maintain records from the fuel supplier providing the sulfur content of fuel and method used to determine sulfur content. The owner or operator must retain the records for five years and provide copies to the Agency upon request. The owner or operator must notify the Agency of any deviations from the sulfur content requirements.

The Agency proposes site-specific exceptions. Subsection (b) provides an exception for Caterpillar Inc. Technical Center in Mossville. The sulfur content for distillate fuel oil must not exceed 500 parts per million and the exemption is limited to 150,000 gallons of fuel per calendar year. Subsection (c) provides an exception for a Caterpillar Inc. facility in Montgomery. The sulfur content for distillate fuel oil must not exceed 500 parts per million. Subsection (d) provides an exception for the electric generating units at Midwest Generation's Fisk and Waukegan stations. The sulfur content for distillate fuel oil must not exceed 500 parts per million in 2017 and 2018. The Board proposed these changes at first notice publication.

In response to comments, the Agency also proposes amending Sections 214.305(a)(3)(A), 214.305(b)(1), 214.305(c)(2)(A), 214.305(c)(2)(B), 214.305(d)(4)(A), 214.305(d)(4)(B), and 214.305(d)(4)(C) to clarify that sources have flexibility regarding the types of records they must maintain to demonstrate compliance with the fuel sulfur content limits set forth in the proposal. Second Mot. Amend at 1. The Board also corrects an error at first notice, replacing the language in Section 214.305(d)(4)(D) stating "within 30 days of receipt after a request by the Agency" with "within 30 days after receipt of a request by the Agency." The Board proposes these additional changes at second notice.

Part 214 Sulfur Limitations
Subpart Q Primary and Secondary Metal Manufacturing

Section 214.421 Combination of Fuels at Steel Mills in Metropolitan Areas

The Agency proposes to update variables used in the equation to calculate SO_2 emission rate when burning a combination of fuels. The Board proposed these changes at first notice publication. In response to Board questions, the Agency further proposes amending this section to correct an error in the metric version of the proposed limit. Second Mot. Amend at 10. The Board proposes this amendment at second notice.

Part 214 Sulfur Limitations
Subpart AA Requirements for Certain SO_2 Sources

Section 214.600 Definitions

The Agency proposes to add nine definitions of terms used in new Subpart AA. One definition identifies the Agency and the remaining eight definitions identify specific facilities. The Board proposed these changes at first notice publication and proposes them at second notice. The Board also replaces Illinois Power Holdings E.D. Edwards with Illinois Power Resources Generating E.D. Edwards, to reflect the direct owner and operator of the facility.

Section 214.601 Applicability

The Agency proposes that new Subpart AA applies to eight facilities and identifies these facilities. The Board proposed these changes at first notice publication and proposes them at second notice. The Board also replaces Illinois Power Holdings E.D. Edwards with Illinois Power Resources Generating E.D. Edwards, to reflect the direct owner and operator of the facility.

Section 214.602 Compliance Deadline

The Agency proposes that new Subpart AA applies on and after January 1, 2017. The Board proposed these changes at first notice publication and proposes them at second notice.

Section 214.603 Emission Limitations

The Agency proposes, for specific units at each of the eight facilities subject to new Subpart AA, a numeric limit on SO_2 emissions in pounds of SO_2 emitted per hour. The Board proposed these limits at first notice publication and proposes them at second notice. At second notice, the Board also corrects the erroneous emission limit of 13.3 lb/hr in Section 214.603(c)(5) to the Agency's proposed 13.36 lb/hr. Additionally, as discussed below, the Board adds a supplemental limit not to exceed 6000 lbs/hour in more than 5% of stack operating hours for the Powerton facility. The Board also replaces Illinois Power Holdings E.D. Edwards with Illinois Power Resources Generating E.D. Edwards, to reflect the direct owner and operator of the facility.

Powerton 30-Day Average Limit. One of these eight facilities, Midwest Generation's Powerton plant, would be allowed to comply with the emission limit on a rolling 30-day average basis. The proposed amendment would set a limit of 3,452 pounds per hour (lb/hr) measured on a 30-day rolling average basis for the combined SO_2 emissions from units at the source. *Id.*

The Agency calculated the hourly emission limit with the 30-day averaging period using USEPA's 2014 Guidance. TSD at 9. The Agency first used modeling to calculate the critical value at which Powerton could emit to achieve the 2010 NAAQS for SO_2. *Id.* This critical value is 6000 lb/hr SO_2 emissions. *Id.* The Agency multiplied the critical value by a ratio of one-hour average emissions to 30-day average emissions. *Id.* at 10. The Agency used emission data from similar units operating with trona injection systems at the Potomac River Generating Station to calculate average emissions and the appropriate ratio. *Id.* The Agency could not use historical data from Powerton units because Powerton has not yet completed installation of the trona injection system. *Id.* at 9. The Agency states that USEPA confirmed that the Agency's analysis and method were consistent with USEPA's 2014 Guidance and that the proposed Powerton limit is appropriate. *Id.* at 10; Agency PC at 20; Agency Ans. 2 at 12 (Q53b).

The Agency explains that it proposed a 30-day averaging period for Powerton because it is difficult for Powerton to comply with an hourly limit due to variability in emissions using trona injection systems as control technology. Agency Ans. 1 at 10 (Q18). The Agency notes that this type of dry sorbent injection equipment is specifically addressed in USEPA's guidance as having the greatest variability in emissions. *Id.* at 10-11; Agency Ans. 2 at 10 (Q51c); Tr. 2 at 54. The Agency also explains that compliance with an hourly standard at Powerton would be difficult because the Powerton units burn fuel with varying sulfur content and installation of all of the control equipment is not yet completed. *Id.*

Public Comments. Sierra Club contends that the Board should require supplemental limits at Powerton because the proposed 30-day averaging period would allow short-term spikes in SO_2 emissions. PC 285 at 16. The 2010 NAAQS for SO_2 is a one-hour standard and Sierra Club contends that USEPA's 2014 Guidance indicates that using a longer-term average poses risks of emission spikes. *Id.* Sierra Club states that the proposed 30-day average would not constrain such emission spikes. *Id.* at 17. Mr. Sahu adds that the Agency provides no technical reason that Powerton cannot meet an hourly limit without 30-day averaging. Sahu at 10. Mr. Sahu notes that all four Powerton units emit from a single stack, allowing for inter-unit averaging. *Id.*

Sierra Club argues that modeling of attainment alone "is not sufficient to support a longer-term average." PC 285 at 17. Sierra Club describes USEPA's guidance as allowing longer-term average limits only when spikes of emissions above the critical emission value will be rare and limited in magnitude. *Id.* at 17-18. Sierra Club suggests, as possible additional constraints, requirements regarding the operation of the control equipment, setting monthly limits on the number of times that emissions can exceed the critical emission value, and setting a cap on the magnitude of peak emissions. *Id.* at 18.

Midwest Generation states that trona injection can lead to emission rate variability, and that performance data for the trona injection system is sparse because installation will not be complete until 2017. PC 283 at 20. IERG supports the 30-day averaging approach for Powerton because it provides operational flexibility while protecting air quality. IERG PC at 7.

Agency Response. USEPA determined that the 30-day average limit for Powerton is acceptable and appropriate. Agency Ans. 2 at 11 (Q51f); Tr. 2 at 55. The Agency argues that USEPA guidance does not require supplemental limits when using longer-term average limits. PC 282 at 19; *see also* 2014 Guidance, Appendix D. The Agency explains that USEPA's 2014 Guidance provides that longer-term averaging is appropriate to address emissions variability and certain types of sources may need longer averaging periods. PC 282 at 4. These types of units include those burning fuel of varying sulfur content, those with variability in their operating load, and those with certain types of pollution control devices. *Id.* Also, units with dry scrubber control technology such as Powerton can have greater variability in emissions than units with wet scrubbers. *Id.*

The Agency also states that the proposed 30-day average emission limit is more stringent than USEPA's 2014 Guidance dictated. PC 4 at 4. USEPA advises that for units with dry scrubber technology, a 37 percent reduction from a modeled one-hour limit would typically be required to demonstrate equivalent stringency for a 30-day average. PC 282 at 22. The Agency proposes a 30-day average limit of 3,452 lb/hr for the Powerton units, adjusted downward from the 6000 lb/hr critical value that was modeled. Tr. 3 at 186. The Agency's proposed limit for Powerton therefore represents a 42 percent downward adjustment. PC 282 at 22. The Agency contends that a similar downward adjustment for a daily average would result in an increase of over 6000 tons per year in allowable emissions at Powerton. *Id.* The Agency maintains that the 30-day average limit for Powerton assures that the NAAQS will be attained and maintained. Agency Ans. 2 at 15 (Q54h).

The Agency states that, while there may be occasional hours in which emissions exceed the modeled 6000 lb/hr critical value, USEPA determined that this averaging methodology is protective of the NAAQS. PC 282 at 2-3. Also, the chances of such a hypothetical exceedance occurring is "vanishingly small." *Id.* at 3. The Agency estimates a less than 1% possibility that there would be a significant exceedance of the critical value coinciding with meteorological conditions conducive for high ambient SO_2 concentrations. Agency Ans. 2 at 13-14 (Q54d). The Agency states that the highest concentration at the receptors at Powerton's fence line was approximately 127 $\mu g/m^3$ (microgram per cubic meter of air), which is below the NAAQS design value 196.32 $\mu g/m^3$. Agency Ans. 2 at 13 (Q54a).

Board Finding. In implementing the 2010 NAAQS for SO_2, USEPA guidance accounts for variability in hourly emissions rates by allowing emission limits with averaging times that are longer than one hour. 2014 Guidance at 24. Such emission limits may use averaging times as long as thirty days and still provide for attainment of the 2010 NAAQS for SO_2. *Id.* USEPA specifically considered dry scrubber technology at units such as Powerton in its guidance. Agency Ans. at 21; Tr. 2 at 69.

Further, as to the concern that 30-day averaging may allow for emission spikes, USEPA explained

> if periods of hourly emissions above the critical emission value are a rare occurrence at a source, particularly if the magnitude of the emissions is not substantially higher than the critical emissions value, these periods would be

> unlikely to have a significant impact on air quality, insofar as they would be very unlikely to occur repeatedly at the times when the meteorology is conducive for high ambient concentrations of SO_2. 2014 Guidance at 24.

USEPA continued that allowing States to use averaging times that are longer than one hour provides "a strong assurance that the NAAQS will be attained and maintained, while still acknowledging the necessary variability in source operations." *Id.*

In its post hearing comments, the Agency suggested a supplemental limit for Powerton. PC 282 at 23-24. The Agency suggests to require the SO_2 emission rate not to exceed 6000 lb/hr (the modeled hourly limit for Powerton units) in more than 5% of the stack operating hours. *Id.* at 24. The Agency consulted with USEPA regarding this supplemental limit and USEPA approves of the limit. *Id., see also* PC 1448 at 24.

The Board finds that the proposed 30-day average limit is appropriate. USEPA reviewed and approved of the proposed limit on Powerton of 3,452 lbs/hr measured on a 30-day rolling average basis. TSD at 10. USEPA further approved a supplemental limit not to exceed 6000 lbs/hour in more than 5% of stack operating hours. PC 282 at 24. The Board finds that the supplemental limit suggested by the Agency addresses the participants' concern regarding emission spikes above the modeled critical value by placing a limit on the number of stack operating hours during which the emissions can exceed the modeled hourly limit. Furthermore, the 30-day average rate of 3452 lbs/hr is 42 percent lower than the modeled one-hour rate of 6000 lbs/hr that would have been proposed for this unit without 30-day averaging. Accordingly, the Board is convinced that the proposed Powerton 30-day average limit of 3452 lbs/hr coupled with the supplemental limit is comparably stringent to the hourly average limit of 6000 lbs/hr and is sufficiently protective of the NAAQS. At second notice, the Board proposes the 30-day average limit as well as the supplemental limit.

Section 214.604 Monitoring and Testing

The Agency proposes monitoring and testing requirements for the eight facilities subject to new Subpart AA. Four of the eight subject facilities are electricity generators. Subject units at these four facilities are required to use continuous emissions monitoring or an alternative method available under 40 CFR 75. Subject units at the remaining four facilities are required to conduct performance testing or use a continuous emissions monitoring system. The Agency proposes detailed procedures for complying with monitoring and testing requirements.

The Board proposed these changes at first notice publication. At second notice, the Board proposes these amendments and also replaces the language in Section 214.604(d) stating "must comply with the following for each those unit" with "must comply with the following for that unit." The Board also replaces Illinois Power Holdings E.D. Edwards with Illinois Power Resources Generating E.D. Edwards, to reflect the direct owner and operator of the facility.

Section 214.605 Recordkeeping and Reporting

The Agency proposes recordkeeping and reporting requirements for facilities subject to new Subpart AA. The Board proposed these changes at first notice publication. In response to Board questions, the Agency also proposes amending this section to specify that the notification required in subsection (e) must include a description of any exceedances of the applicable emission limits in Section 214.603, and a discussion of the possible cause of any exceedances. Second Mot. Amend at 11. The Board proposes these amendments at second notice.

Part 217 Nitrogen Oxides Emissions
Subpart M Electric Generating Units

Section 217.342 Exemptions

Part 217 addresses NO_x emissions from stationary sources. Subparts under Part 217 provide general requirements and requirements for specific types of sources. Relevant here, Subpart M titled “Electrical Generating Units” applies to fossil fuel-fired boilers. 35 Ill. Adm. Code 217.340. Section 217.344 sets numeric limits on NO_x emissions based on fuel. 35 Ill. Adm. Code 217.344. Section 217.342 exempts certain units. The Agency proposes to add an exemption providing that if a fossil fuel-fired boiler is covered by the CPS in 35 Ill. Adm. Code 225.Subpart B (Sections 225.291 through 225.299), then that boiler is not subject to Part 217 Subpart M, regardless of the type of fuel combusted. The Board proposed these changes at first notice publication and proposes them at second notice.

Part 217 Nitrogen Oxides Emissions
Subpart Q Stationary Reciprocating Internal Combustion Engines and Turbines

Section 217.394 Testing and Monitoring

The Agency proposes to specify an initial performance testing deadline for new units. The Board proposed these changes at first notice publication and proposes them at second notice.

Part 225 Control of Emissions from Large Combustion Sources
Subpart B Control of Mercury Emissions from Coal-Fired Electric Generating Units

Section 225.205 Applicability

The Agency proposes to specify that stationary boilers listed in Part 225 Appendix A are subject to Subpart B regardless of the type of fuel combusted. The Board proposed these changes at first notice publication and proposes them at second notice.

Section 225.210 Compliance Requirements

The Agency proposes changes to be consistent with changes to the CPS for units that cease combusting coal. The Board proposed these changes at first notice publication and proposes them at second notice.

Section 225.240 General Monitoring and Reporting Requirements

The Agency proposes changes to be consistent with changes to the CPS for units that cease combusting coal. The Board proposed these changes at first notice publication and proposes them at second notice.

<u>Section 225.265 Coal Analysis for Input Mercury Levels</u>

The Agency proposes changes to be consistent with changes to the CPS for units that cease combusting coal. The Board proposed these changes at first notice publication. The Board proposes these changes at second notice, and includes in Section 225.265(a) a comma at the end of the added text "or that has permanently ceased combusting coal." This is to clarify that the phrase "must fulfill the following requirements" applies to the entire preceding paragraph.

<u>Section 225.290 Recordkeeping and Reporting</u>

The Agency proposes changes to be consistent with changes to the CPS for units that cease combusting coal. The Board proposed these changes at first notice publication and proposes them at second notice.

<u>Section 225.291 Combined Pollutant Standard: Purpose</u>

The CPS provides alternative means to comply with mercury emissions standards by instead shutting down units and installing pollution control technology for NO_x, SO_2, and particulate matter that also reduce mercury. The Agency proposes to add language to this section stating that converting to a fuel other than coal such as natural gas or distillate fuel oil with a sulfur content no greater than 15 parts per million also is an alternative means to comply with mercury emission standards. The Board proposed these changes at first notice publication and proposes them at second notice.

<u>Section 225.292 Applicability of the Combined Pollutant Standard</u>

The CPS applies to electric generating units listed in Appendix A to Part 225. The Agency proposes changes to provide that the CPS applies to units listed in Appendix A regardless of the type of fuel combusted by the unit. The Board proposed these changes at first notice publication. In response to Board questions, the Agency further proposes amending this section to change "including" to "such as" for purposes of consistency with Section 225.291. Second Mot. Amend at 12. The Board proposes this amendment at second notice.

<u>Section 225.293 Combined Pollutant Standard: Notice of Intent</u>

The Agency proposes a requirement for the owner or operator of an electric generating unit listed in Appendix A who changes the type of fuel combusted by the unit or a control device on the unit to notify the Agency of the change. The Board proposed these changes at first notice publication and proposes them at second notice.

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

The Agency proposes to prohibit Will County 3 station from combusting coal on or after April 16, 2015. The Agency proposes to remove control, monitoring, and other requirements relating to mercury emissions for units not combusting coal. The Board proposed these changes at first notice publication and proposes them at second notice.

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

The Agency proposes a provision specifying that electric generating units subject to the CPS are not subject to Part 217 Subpart M including the NO_x emission standards in Section 217.344. Further, the SO_2 emission rate limit only applies to coal-fired units subject to the CPS. The Board proposed these changes at first notice publication. At second notice, the Board includes a change to Section 225.295(d) clarifying that, for purposes of subsections (b) and (d) only, "CPS group" includes only those specified EGUs that combust coal.

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

The Agency proposes to prohibit Will County 3 from combusting coal on or after April 16, 2015. Joliet 6, 7, and 8 are prohibited from combusting coal on or after December 31, 2016. Except for Will County 4, all other subject units must permanently shut down, permanently cease combusting coal, or install FGD equipment on or before December 31, 2018. The Board proposed these changes at first notice publication and proposes them at second notice.

At second notice, the Board also makes corrections, noting that the first sentence in Section 225.296(b) is new text, and removing the underline from the existing term "of" in the third sentence.

The Agency also proposes to change the compliance deadline for Waukegan 7 to reflect the variance granted by the Board in Midwest Generation, LLC – Waukegan Generating Station v. IEPA, PCB 12-121. The variance extended Waukegan 7's compliance deadline from December 31, 2013, to December 31, 2014. The Board withdraws the change proposed at first notice because both dates have passed. Additionally, as discussed below, the Board lowers the emission limit for Will County 4.

Exemption for Will County 4. Section 225.296 sets forth control technology requirements for SO_2, NO_x, and particulate matter emissions under the CPS. Will County 4 is covered by Section 225.296(b), which states

> Other Control Technology Requirements for SO_2. Owners or operators of specified EGUs must either permanently shut down or install FGD equipment on

> each specified EGU (except Joliet 5), on or before December 31, 2018, unless an earlier date is specified in subsection (a) of this Section.[1]

Thus, under the current rules, Midwest Generation is required to permanently shut down or install FGD equipment on Will County 4 on or before December 31, 2018. 35 Ill. Adm. Code 225.296(b).

Midwest Generation intends to convert four coal-fired units – Joliet 6, 7, and 8, and Will County 3 – to natural gas or distillate fuel oil. SR at 9-10. The conversion of these units results in significant reduction of SO_2 emissions that surpass the reductions that would be achieved under the current CPS rule. PC 282 at 27. These four units include Joliet 6, which under the current rules is exempt from installing FGD equipment under Section 225.296(b). *Id.* Midwest Generation intends to continue burning coal at Will County 4, and requested that the unit be exempt from the requirement to install FGD equipment in lieu of Joliet 6 having the exemption. SR at 12. The Agency included this request in its proposed amendments to Part 225 and proposed a SO_2 emission limit applicable to Will County 4 in Part 214 that reflects the fuel conversion. SR at 12. Specifically, the Agency proposes to exempt Will County 4 from the requirement to shut down or install FGD equipment on or before December 31, 2018.

Public Comments. Sierra Club objects to exempting Will County 4 from the control requirements in Section 225.296(b). PC 285 at 8. Sierra Club argues that Will County 4 has a larger impact than the Joliet unit on the violating Lockport receptor in the Lemont nonattainment area. *Id.* Accordingly, installing FGD equipment on Will County 4 is the most reasonable strategy to achieve attainment at that receptor. *Id.* Will County 4 contributes 150 $\mu g/m^3$ at the Lockport receptor, whereas each Joliet unit is contributing less than 0.05 $\mu g/m^3$. *Id.* Therefore, a reduction from Joliet will have a much smaller impact on the Lockport receptor than the same reduction at Will County 4. *Id.* at 10. Accordingly, switching the exemption from Joliet to Will County is not an equal trade. *Id.* Sierra Club further states that, even if FGD is not required for NAAQS attainment, installation of FGD controls would improve air quality and provide public health benefits. *Id.* at 13-14. Sierra Club states that the community around Will County 4 "has the right to the pollution reductions and air quality improvements that would stem from" the CPS. *Id.* at 14.

CARE also objects to the exemption for Will County 4. PC 148 at 1. CARE claims that Will County 4 and Joliet 6 are not comparable in size, emissions, or environmental impact. *Id.* at 5. CARE notes that Will County 4 is roughly equivalent to two Joliet 6-sized units. *Id.* at 6. Further, CARE notes that the Joliet facility is not in the boundaries of the Lemont nonattainment area and does not contribute to nonattainment in the Lemont area. *Id.* at 7. SO_2 reductions at the Joliet facility are therefore not equal in value to reductions where Will County 4 operates. *Id.*

CARE contends that the Agency's proposal for an alternative emission standard for Will County 4 is premature until the effectiveness of FGD at Waukegan and Powerton is known. PC 148 at 9-10. Under the CPS group emission rate, the better controlled the distant Waukegan and

[1] The Joliet 6 EGU was ambiguously identified in this section as "Joliet 5" because Joliet 6 is powered by Boiler 5 at the facility. TSD at 11. Any reference in this opinion to "Joliet 6" refers to the "Joliet 5" unit identified in 35 Ill. Adm. Code 225.296(b).

Powerton units are, the greater the emissions that would be allowable from Will County 4 in the Lemont nonattainment area. *Id.* at 10. The Agency's proposal, therefore, prematurely sets an adjusted emission standard for Will County 4 without having actual emissions data to determine this standard. *Id.* Further, without this data, the Agency cannot determine the local impacts of the actual emissions from Will County 4. *Id.* at 10-11.

Agency Response. The Agency notes that Will County 4 will be subject to group annual SO_2 emission rates in 35 Ill. Adm. Code 225.295(b). Agency Ans. 2 at 8 (Q48); Tr. 2 at 21. The Agency further states that its modeling demonstrates that the 2010 NAAQS for SO_2 will be attained at the fence line of the Will County facility, as well as throughout the entire nonattainment area. Agency Ans. 2 at 9 (Q50). The Agency's modeling demonstrated that attainment in the Lemont area would be achieved without installing FGD at Will County 4. Agency Ans. 2 at 9; Agency Ans. 3 at 11. The proposal limits Will County 4's emissions to levels needed to demonstrate attainment and eliminates the need for FGD equipment. PC 282 at 26.

The exemption for Will County 4 is part of a combination of requirements for Midwest Generation units impacting the Lemont nonattainment area. *Id.* at 27. The Agency states that the proposal, across all Midwest Generation units, will result in SO_2 emission reductions of more than 6000 tons in 2017 compared to current CPS requirements. TSD at 11. At the Will County facility, the proposal results in SO_2 emissions of approximately 30-35%. PC 282 at 27; Agency Ans. 3 at 11 (Q67c).

Board Finding. The CPS was established "as an alternative means of compliance with the proposed emissions standards for mercury in Subpart B, Section 225.230(a)." Proposed New Clean Air Interstate Rules (CAIR) SO_2, NO_x Annual and NO_x Ozone Season Trading Programs, 35 Ill. Adm. Code 225, Subparts A, C, D, E, and F, R06-26, slip op. at 41 (April 19, 2007). The CPS further established specific emissions levels for NO_x, particulate matter, and SO_2. *Id.* The Board found that the CPS would achieve greater reductions in SO_2, NO_x, and mercury than the proposed CAIR standards. CAIR, R06-26, slip op. at 21 (Aug. 23, 2007).

Will County 4 will continue to be subject to the group-wide SO_2 emission rate adopted by the Board in the CAIR rulemaking. The current proposal does not change the numerical SO_2 emission rate applicable to Will County 4.

Furthermore, Will County 4's contribution of 150 $\mu g/m^3$ on the most impacted receptor in the Lemont nonattainment area is well below the NAAQS design value of 196.32 $\mu g/m^3$. PC 282 at 29. Total contributions to that receptor are 191.5 $\mu g/m^3$, also below the NAAQS design value. *Id.* Furthermore, the highest concentration at the receptors at Will County's fence line was approximately 110.5 $\mu g/m^3$. Agency Ans. 2 at 9 (Q50). The Agency's proposed emission limit for Will County 4 is therefore protective of the NAAQS and installing FGD equipment is not necessary to attain the NAAQS at this time.

The Agency predicts that SO_2 emissions at the Will County station overall will decrease as compared to emissions under the current CPS due to the proposed prohibition on burning coal in Will County 3. The Agency calculates that Will County 3 and 4 together will emit 2261 tons in 2017 under the proposed rules as compared to 3516 tons under the CPS. TSD at 17, Table 4. The Agency's proposal will result in reduction of SO_2 emissions of approximately 30-35% at the Will County facility as a whole. Agency Ans. 2 at 11 (Q67). If Midwest Generation were to continue complying with the current CPS requirements, emissions from the CPS group would be higher than under the Agency's proposed amendments. Under the Agency's proposal, emissions of SO_2, NO_x, carbon dioxide, particulate matter, and mercury are reduced below the levels achieved by the CPS. On a CPS group-wide basis, this benefits public health and the environment beyond that previously envisioned in adopting the CPS.

The Agency, in its post-hearing filing, offered to amend its proposal to lower the hourly emission limit for Will County 4. PC 282 at 29. The Agency proposes an emission limit of 5,000 lb/hr, down from 6,520.65 lb/hr as originally proposed. *Id.* at 30. The Agency describes this amendment as an approximate 23% reduction in Will County 4's allowable emissions, which translates to a roughly 30 $\mu g/m^3$ reduction in the modeled design value at the violating Lockport receptor. *Id.* at 29. This amendment creates a greater margin of safety than already exists in the Agency's current proposal. *Id., see also* PC 1448 at 23.

Based on the rulemaking record, the Board agrees with the Agency's position that the proposal will achieve attainment in the Lemont nonattainment area even with an FGD exemption for Will County 4. Will County 4's impact on the most impacted receptor in the Lemont nonattainment area, and the total impact of all modeled sources on that receptor, is less than the NAAQS design value of 196.32 $\mu g/m^3$. The amended 5,000 lb/hr limit, as opposed to the previous 6,520.65 lb/hr limit, is a 23 percent reduction in Will County 4's allowable emissions and will further reduce the impact at this receptor to roughly 161.5 $\mu g/m^3$, well below the NAAQS design value of 196.32 $\mu g/m^3$. The Board therefore proposes these changes at second notice.

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

The Agency proposes changes to eliminate a provision allowing emission allowances to be sold, traded, or transferred to the Homer City Pennsylvania generating station. The Board proposed these changes at first notice publication. The Board proposes these changes at second notice and also corrects an error in the renumbering of the subparagraphs, replacing (a)(3) with (a)(2).

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

The Agency proposes to remove the reference to Midwest Generation from the title of this appendix. The Board proposed these changes at first notice publication and proposes them at second notice.

ECONOMIC REASONABLENESS AND TECHNICAL FEASIBILITY

Section 27(a) of the Act directs the Board to take into account the "technical feasibility and economic reasonableness of measuring or reducing the particular type of pollution" when conducting a rulemaking. 415 ILCS 5/27(a) (2014). Section 27(b) of the Act further requires the Board to determine whether a proposed substantive regulation "has any adverse economic impact on the people of the State of Illinois." 415 ILCS 5/27(b) (2014). For the reasons below, the Board finds that the proposed rules are technically feasible and economically reasonable and will not have an adverse economic impact on citizens of Illinois.

As required by Section 27(b) of the Act (415 ILCS 5/27(b) (2014)), the Board requested that the Department of Commerce and Economic Opportunity (DCEO) conduct an economic impact study of the Agency's rulemaking proposal. DCEO declined to undertake such a study. During each hearing, the hearing officer afforded those present an opportunity to address the Board's request for a study and DCEO's response. Tr. 1 at 63; Tr. 2 at 131; Tr. 3 at 268. The Board received no comments on the request or response.

The Agency states that, in determining the necessary emission limits for the affected sources in Subpart AA of Part 214, it consulted with those sources to ensure the proposed emission rates could feasibly be achieved. TSD at 19. The Agency states that potentially affected sources "agreed that the limits in the proposed amendments can be feasibly complied with." *Id.* The Agency further states that the proposed liquid fuel standards rely primarily on data demonstrating that the majority of commercial and industrial sources in Illinois currently are using fuel oils compliant with the proposed amendments. *Id.* The Agency states that fuels required to comply with the proposed standards are widely available in Illinois. *Id.* at 20. In 2011, ultra-low sulfur diesel made up 87.6% of all distillate fuel used in the commercial sector, and 68.5% of all distillate fuel in the industrial sector. *Id.* at 19. The Agency notes that a number of other states, including New York, Connecticut, New Jersey, Maine, Massachusetts, and Vermont, have similar rules to those proposed. *Id.* at 20-21.

The Agency states that the majority of its proposed revisions to Part 214 are to satisfy Illinois' obligation to submit an implementation plan to USEPA to address requirements of the Clean Air Act for areas designated as nonattainment with respect to the 2010 NAAQS for SO_2. SR at 6. The Agency states that affected sources in Subpart AA of Part 214 agreed that the proposed emission limits could be achieved in an economically reasonable manner. TSD at 22. The Agency further states that federal regulations currently limit fuel sulfur content to 15 parts per million for all highway vehicles, large stationary engines, non-road vehicles and equipment, marine engines, and locomotive engines. *Id.* at 23. As a result, the Agency believes any increase in price from its proposed liquid fuel standards is unlikely, as such increase already has occurred. *Id.* at 22. The Agency also states that ultra-low sulfur diesel "is widely available" in Illinois, and that higher-sulfur diesel fuel may be difficult to find in 2015. Agency Ans. 1 at 4 (Q5). The Agency states that a number of fuel oil distributors currently only offer ultra-low sulfur diesel. *Id.* In addition, IERG's expert testified that ultra-low sulfur diesel is in widespread use in Illinois, and that the limited exceptions "have been modeled to show that attainment of the NAAQS would not be threatened or impeded." Kolaz Test. at 6.

Midwest Generation commented on economic reasonableness and technical feasibility of the rules relating to its operations. Midwest Generation states that a 30-day average for SO_2 emissions from its Powerton facility is needed because the one-hour rate identified by the Agency cannot be achieved at all required times due to the variability in the expected Powerton

SO_2 emissions. PC 283 at 28. Further, a FGD requirement at Will County 4 and a one hour SO_2 rate at Powerton "are not necessary to attain the SO_2 NAAQS in the Lemont and Pekin areas." *Id.* Midwest Generation states that substantial costs would be imposed on it to comply with these goals and are not needed to attain the SO_2 NAAQS. *Id.* Midwest Generation committed up to $350 million to comply with environmental requirements at Powerton and Joliet, including the planned Joliet unit conversion from coal to gas, and the installation of trona injection systems at Powerton. *Id.* at 4. Further, Midwest Generation is one of only a few companies required to incur costs to reduce actual SO_2 emissions to comply with the proposal. *Id.* at 28. The Agency estimates conversion costs for Midwest Generation from $100-$150 million, before factoring in infrastructure and transportation costs. Agency Ans. 3 at 8 (Q65a). The Agency also estimates that converting Will County 4 to a fuel other than coal would cost from $30-$45 million, excluding infrastructure costs. Agency Ans. 3 at 6-7 (Q62e). Installing FGD equipment on Will County 4 could range from $24-$90 million, with Midwest Generation noting in previous Board proceedings that capital costs for installing a trona injection system averages $38 million per unit. *Id.*

Based on the record, the Board finds that the proposed rules in the order below are technically feasible, and economically reasonable, to meet Illinois' obligations under the Clean Air Act and to satisfy Illinois' obligation to submit a SIP to USEPA for approval with respect to the 2010 NAAQS for SO_2. The Board also finds that the proposed rules will not have an adverse economic impact on the people of Illinois.

JOINT COMMITTEE ON ADMINISTRATIVE RULES SUGGESTED CHANGES

The Board includes for second notice publication the majority of JCAR's suggested non-substantive changes to the rules. These changes are discussed in the section-by-section breakdown above. The proposal at various areas requires certain owners or operators to "[m]aintain records demonstrating that the fuel oil used by the fuel combustion emission source complies with" certain requirements, "such as records from the fuel supplier indicating the sulfur content of the fuel oil." *See, e.g.*, proposed 35 Ill. Adm. Code 214.122(b)(2)(C)(i). JCAR proposes amending this language to state that the records be "including records from the fuel supplier indicating the sulfur content of the fuel oil." The Board declines to make this amendment because the term "including" may cause confusion regarding whether those records are necessary to be kept, as opposed to being examples of what records may be kept.

CONCLUSION

The Board proposes for second notice review by JCAR the following amendments to its air pollution regulations in Parts 214, 217, and 225.

ORDER

The Board directs the Clerk to provide the following proposed amendments to JCAR for second notice review. Proposed additions are underlined and proposed deletions are struck. Additions following first notice are double underlined, and deletions following first notice are double struck through.

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

214.183	General Formula
214.184	Special Formula
214.185	Alternative Emission Rate
214.186	New Operating Permits

SUBPART F: ALTERNATIVE STANDARDS FOR SOURCES INSIDE METROPOLITAN AREAS

Section	
214.201	Alternative Standards for Sources in Metropolitan Areas
214.202	Dispersion Enhancement Techniques

SUBPART K: PROCESS EMISSION SOURCES

Section	
214.300	Scope
214.301	General Limitation
214.302	Exception for Air Pollution Control Equipment
214.303	Use of Sulfuric Acid
214.304	Fuel Burning Process Emission Source
214.305	Fuel Sulfur Content Limitations

SUBPART O: PETROLEUM REFINING, PETROCHEMICAL AND CHEMICAL MANUFACTURING

Section	
214.380	Scope
214.381	Sulfuric Acid Manufacturing
214.382	Petroleum and Petrochemical Processes
214.383	Chemical Manufacturing
214.384	Sulfate and Sulfite Manufacturing

SUBPART P: STONE, CLAY, GLASS AND CONCRETE PRODUCTS

Section	
214.400	Scope
214.401	Glass Melting and Heat Treating
214.402	Lime Kilns

SUBPART Q: PRIMARY AND SECONDARY METAL MANUFACTURING

Section	
214.420	Scope
214.421	Combination of Fuels at Steel Mills in Metropolitan Areas
214.422	Secondary Lead Smelting in Metropolitan Areas
214.423	Slab Reheat Furnaces in St. Louis Area

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 at 7 Ill. Reg. 13597; 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; amended in R15-21 at 39 Ill. Reg. _______, effective __________.

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~~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 214.10(e). ~~(Ill. Rev. Stat. 1989, ch. 111 ½, 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~~Appendix~~ A, Method 8, incorporated~~incoporated~~ 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 mm~~million~~Btu/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.

d) Weekly Analysis Method. This subsection applies to sources at plants with total solid fuel-fired heat input capacity exceeding 146.5 MW (500 mm~~million~~Btu/hr) but not exceeding 439.5 MW (1500 mm~~million~~Btu/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 mm~~millions~~Btu/hr) but not exceeding 146.5 MW (500 mm~~million~~Btu/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 mm~~million~~Btu/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 (~~1989~~2014):

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;

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

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

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

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

~~5~~9) 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) (~~1989~~2014), 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 (~~1989~~2014).

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~~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~~Board Note~~: This Section~~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.

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 greater than 73.2 MW (250 mmB~~b~~tu/hr), burning liquid fuel exclusively, to exceed the following:

   ~~1~~A) ~~To exceed~~ 1.2 kg of sulfur dioxide per MW-hr of actual heat input when residual fuel oil is burned (0.8 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);~~.~~

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:

   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), such as~~including~~ records from the fuel supplier indicating~~indicting~~ the sulfur content of the fuel oil~~and the method used to determine sulfur content~~;

      ii) Retain the records for at least 5 years, and provide copies of the records to the Agency within 30 days after 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, the 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 214.122 Small Sources

This Section~~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:

~~1~~A) ~~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

~~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);~~.~~

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), such as records from the fuel supplier indicating the sulfur content of the fuel oil ~~and the method used to determine sulfur content~~;

ii) Retain the records for at least 5 years, and provide copies of the records to the Agency within 30 days after 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, the 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:

~~a~~1) ~~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

~~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).

b) Except as provided in subsections (c)~~,~~ and (d)~~, and (e)~~, 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), such as records from the fuel supplier indicating the sulfur content of the fuel oil ~~and the method used to determine sulfur content~~;

B) Retain the records for at least 5 years, and provide copies of the records to the Agency within 30 days after 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, the 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) 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 E. Greenwood Avenue, Waukegan IL), and Will County station (located at or near 529 E. 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), such as ~~the date of purchase and~~ 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~~ and the method used to determine sulfur content~~;

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), such as records from the fuel supplier indicating the sulfur content of the fuel oil~~ and the method used to determine sulfur content~~;

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), such as records from the fuel supplier indicating the sulfur content of the fuel oil~~ and the method used to determine sulfur content~~;

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 after 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, the 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;

~~5) Maintain records indicating the amount of distillate fuel oil used by the fuel combustion 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 (c), including records from the fuel supplier indicating the sulfur content of the fuel oil and the method used to determine sulfur content;~~

~~6) Retain the records for at least 5 years, and provide copies of the records to the Agency within 30 days after receipt of a request by the Agency; and~~

~~7) 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, the 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) 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 the 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), such as ~~the date of purchase and~~ 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 ~~and the method used to determine sulfur content~~;

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), such as records from the fuel supplier indicating the sulfur content of the fuel oil ~~and the method used to determine sulfur content~~;

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 after 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, the 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/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	MW	mmB~~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 mmB~~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 mmB~~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. Nothing in this Section, however, excuses a source subject to Subpart AA from complying with the requirements set forth in that Subpart.

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 after~~of~~ approval of that~~such~~ standard for a revision of its operating permit for the~~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 214.301 General Limitation**~~

~~Except as further provided by this Part, no person shall cause or allow the emission of sulfur dioxide into the atmosphere from any process emission source to excess 2000 ppm on a dry basis, when averaged over a one-hour period.~~

~~(Source: Amended at 39 Ill. Reg.__________, effective________)~~

Section 214.305 Fuel Sulfur Content Limitations

a) Except as provided in subsections (b), (c), and (d), 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), such as records from the fuel supplier indicating the sulfur content of the fuel oil ~~and the method used to determine sulfur content~~;

B) Retain the records for at least 5 years, and provide copies of the records to the Agency within 30 days after 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) 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 E. 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 the fuel oil must not exceed 500 ppm. The owner or operator of the process emission sources described in this subsection 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 the fuel oil complies with the requirements in this subsection (b), such as records from the fuel supplier indicating the sulfur content of the fuel oil~~ and the method used to determine sulfur content~~;

2) Retain the records for at least 5 years, and provide copies of the records to the Agency within 30 days after 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, the 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) 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 these 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 ~~the date of purchase and ~~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~~the method used to determine sulfur content~~;

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), such as records from the fuel supplier indicating the sulfur content of the fuel oil ~~and the method used to determine sulfur content~~;

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 after 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, the 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) 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 E. Greenwood Avenue, Waukegan IL). The owner or operator of these 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 these 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 these 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 these 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), such as ~~the date of purchase and~~ 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 ~~and the method used to determine sulfur content~~;

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), such as records from the fuel supplier indicating the sulfur content of the fuel oil~~ and the method used to determine sulfur content~~;

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), such as records from the fuel supplier indicating the sulfur content of the fuel oil~~ and the method used to determine sulfur content~~;

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 after 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, the 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 meanings 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 S. 2nd Street, Pekin IL.

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

"Ingredion Bedford Park" means the corn wet milling source located at or near 6400 S. 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 E. 135th, Romeoville IL.

"Owens Corning" means the asphalt and roofing products manufacturing source located at or near 5824 S. 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 Resources Generating E.D. Edwards ~~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) 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 Resources Generating E.D. Edwards~~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) 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) combusts any fuel;

3) Within 24 hours after 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) 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):

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

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) (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.

4) The SO_2 emission rate for the emission units addressed in subsection (e)(1) of this Section must not exceed 6,000 lb/hr in more than 5% of the stack operating hours (“n” in the equation above) in any averaging period.

f) Midwest Generation Will County — lb/hr

1) Unit 3 — 145.14

2) Unit 4 — 5000~~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, demonstrate compliance with the applicable emission limitations in Section 214.603 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, 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 through 34), incorporated by reference in Section 214.104, and subsection (d), or utilize an alternative monitoring method available to the emission unit under 40 CFR 75:

1) Illinois Power Resources Generating E.D. Edwards~~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) must, for each emission unit at the source that is addressed in Section 214.603, 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 through 34), incorporated by reference in Section 214.104, 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 ~~those~~ unit:

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

2) If the owner or operator of an emission unit subject to Section 214.604(c) changes the method of demonstrating compliance for that 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); and

3) The provisions in 40 CFR 75.31 through 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) changes the method of demonstrating compliance for that 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) begins the 5-year period;

3) Conduct additional performance testing when, in the opinion of the Agency or USEPA, that testing is necessary to demonstrate compliance with the requirements in Section 214.603. The 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, to the Agency at least 45 days prior to a scheduled emissions test, unless that 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 those 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 Method 1, 2, 3, 4, 6, 6A, 6B, 6C, or 19, incorporated by reference in Section 214.104, 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 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 each 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);

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 those parameters will ensure ongoing compliance with the applicable limitation in Section 214.603 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 or methods the source will use to comply with all applicable emission limitations in Section 214.603, including a description of all control devices used and, for sources with emission units demonstrating compliance through performance testing, the operating parameters for those devices.

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

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;

5) The date, time, and duration of any malfunction in the operation of an emission unit addressed in Section 214.603 or any SO_2 control equipment for that unit, if the malfunction causes an exceedance of any applicable emission limitation in Section 214.603, and the date, time, and duration of any malfunction in the operation of any SO_2 emissions monitoring equipment for that 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, including the date and nature of those activities. The 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), 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) 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. 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. The 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);

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. The 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);

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 the parameters will ensure ongoing compliance with the applicable limitation in Section 214.603 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. The 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. At minimum, and in addition to any permitting obligations, the 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 the records to the Agency within 30 days after 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 217
NITROGEN OXIDES EMISSIONS
SUBPART A: GENERAL PROVISIONS

SUBPART F: PROCESS HEATERS

Section
217.180 Applicability
217.182 Exemptions
217.184 Emissions Limitations
217.185 Combination of Fuels
217.186 Methods and Procedures for Combustion Tuning

SUBPART G: GLASS MELTING FURNANCES

Section
217.200 Applicability
217.202 Exemptions
217.204 Emissions Limitations

SUBPART H: CEMENT AND LIME KILNS

Section
217.220 Applicability
217.222 Exemptions
217.224 Emissions Limitations

SUBPART I: IRON AND STEEL AND ALUMINUM MANUFACTURING

Section
217.240 Applicability
217.242 Exemptions
217.244 Emissions Limitations

SUBPART K: PROCESS EMISSION SOURCES

Section
217.301 Industrial Processes

SUBPART M: ELECTRICAL GENERATING UNITS

Section
217.340 Applicability
217.342 Exemptions
217.344 Emissions Limitations
217.345 Combination of Fuels

SUBPART O: CHEMICAL MANUFACTURE

Section
217.381 Nitric Acid Manufacturing Processes

SUBPART Q: STATIONARY RECIPROCATING INTERNAL COMBUSTION ENGINES AND TURBINES

SUBPART T: CEMENT KILNS

SUBPART U: NO_x CONTROL AND TRADING PROGRAM FOR SPECIFIED NO_x GENERATING UNITS

SUBPART V: ELECTRIC POWER GENERATION

SUBPART W: NO_x TRADING PROGRAM FOR ELECTRICAL GENERATING UNITS

Section

SUBPART X: VOLUNTARY NO_x EMISSIONS REDUCTION PROGRAM

Section

Authority: Implementing Sections 9.9 and 10 and authorized by Sections 27 and 28.5 of the Environmental Protection Act [415 ILCS 5/9.9, 10, 27 and 28.5 (2004)].

SOURCE: Adopted as Chapter 2: Air Pollution, Rule 207: Nitrogen Oxides Emissions, R71-23, 4 PCB 191, April 13, 1972, filed and effective April 14, 1972; amended at 2 Ill. Reg. 17, p. 101, effective April 13, 1978; codified at 7 Ill. Reg. 13609; amended in R01-9 at 25 Ill. Reg. 128, effective December 26, 2000; amended in R01-11 at 25 Ill. Reg. 4597, effective March 15, 2001; amended in R01-16 and R01-17 at 25 Ill. Reg. 5914, effective April 17, 2001; amended in R07-18 at 31 Ill. Reg. 14271, effective September 25, 2007; amended in R07-19 at 33 Ill. Reg. 11999, effective August 6, 2009; amended in R08-19 at 33 Ill. Reg. 13345, effective August 31, 2009; amended in R09-20 at 33 Ill. Reg. 15754, effective November 2, 2009; amended in R11-17 at 35 Ill. Reg. 7391, effective April 22, 2011; amended in R11-24 at 35 Ill. Reg. 14627, effective August 22, 2011; amended in R11-08 at 35 Ill. Reg. 16600, effective September 27, 2011; amended in R09-19 at 35 Ill. Reg. 18801, effective October 25, 2011; amended in R15-21 at 39 Ill. Reg.__________, effective____________.

SUBPART M: ELECTRICAL GENERATING UNITS

Section 217.342 Exemptions

a) Notwithstanding Section 217.340, the provisions of this Subpart do not apply to a fossil fuel-fired stationary boiler operating under a federally enforceable limit of NO_x emissions from such boiler to less than 15 tons per year and less than five tons per ozone season.

b) Notwithstanding Section 217.340, the provisions of this Subpart do not apply to a coal-fired stationary boiler that commenced operation before January 1, 2008, that is complying with 35 Ill. Adm. Code 225.Subpart B through the multi-pollutant standard~~ or the combined pollutant standard~~.

c) Notwithstanding Section 217.340, the provisions of this Subpart do not apply to a fossil fuel-fired stationary boiler that is subject to any of the requirements in the combined pollutant standard in 35 Ill. Adm. Code 225.Subpart B (Sections 225.291 through 225.299), regardless of the type of fossil fuel combusted.

(Source: Amended at 39 Ill. Reg.__________, effective___________)

SUBPART Q: STATIONARY RECIPROCATING INTERNAL COMBUSTION ENGINES AND TURBINES

Section 217.394 Testing and Monitoring

a) An owner or operator must conduct an initial performance test pursuant to subsection (c)(1) or (c)(2) of this Section as follows:

1) By January 1, 2008, for affected engines listed in Appendix G. Performance tests must be conducted on units listed in Appendix G, even if the unit is included in an emissions averaging plan pursuant to Section 217.388(a)(2).

2) By the applicable compliance date set forth in Section 217.392, or within the first 876 hours of operation per calendar year, whichever is later:

A) For affected units not listed in Appendix G that operate more than 876 hours per calendar year; and

B) For units that are not affected units that are included in an emissions averaging plan and operate more than 876 hours per calendar year.

3) Once within the five-year period after the applicable compliance date as set forth in Section 217.392 or once within the five-year period following the date the unit commenced operation:

A) For affected units that operate fewer than 876 hours per calendar year; and

B) For units that are not affected units that are included in an emissions averaging plan and that operate fewer than 876 hours per calendar year.

b) An owner or operator of an engine or turbine must conduct subsequent performance tests pursuant to subsection (b)(1), (b)(2), and (b)(3) of this Section as follows:

1) For affected engines listed in Appendix G and all units included in an emissions averaging plan, once every five years. Testing must be

performed in the calendar year by May 1 or within 60 days after starting operation, whichever is later;

2) If the monitored data shows that the unit is not in compliance with the applicable emissions concentration or emissions averaging plan, the owner or operator must report the deviation to the Agency in writing within 30 days and conduct a performance test pursuant to subsection (c) of this Section within 90 days of the determination of noncompliance; and

3) When, in the opinion of the Agency or USEPA, it is necessary to conduct testing to demonstrate compliance with Section 217.388, the owner or operator of a unit must, at his or her own expense, conduct the test in accordance with the applicable test methods and procedures specified in this Section within 90 days after receipt of a notice to test from the Agency or USEPA.

c) Testing Procedures:

1) For an engine: The owner or operator must conduct a performance test using Method 7 or 7E of 40 CFR 60, appendix A, as incorporated by reference in Section 217.104. Each compliance test must consist of three separate runs, each lasting a minimum of 60 minutes. NO_x emissions must be measured while the affected unit is operating at peak load. If the unit combusts more than one type of fuel (gaseous or liquid), including backup fuels, a separate performance test is required for each fuel.

2) For a turbine: The owner or operator must conduct a performance test using the applicable procedures and methods in 40 CFR 60.4400, as incorporated by reference in Section 217.104.

d) Monitoring: Except for those years in which a performance test is conducted pursuant to subsection (a) or (b) of this Section, the owner or operator of an affected unit or a unit included in an emissions averaging plan must monitor NO_x concentrations annually, once between January 1 and May 1 or within the first 876 hours of operation per calendar year, whichever is later. If annual operation is less than 876 hours per calendar year, each affected unit must be monitored at least once every five years. Monitoring must be performed as follows:

1) A portable NO_x monitor utilizing method ASTM D6522-00, as incorporated by reference in Section 217.104, or a method approved by the Agency must be used. If the engine or turbine combusts both liquid and gaseous fuels as primary or backup fuels, separate monitoring is required for each fuel.

2) NO_x and O_2 concentrations measurements must be taken three times for a duration of at least 20 minutes. Monitoring must be done at highest

achievable load. The concentrations from the three monitoring runs must be averaged to determine whether the affected unit is in compliance with the applicable emissions concentration or emissions averaging plan, as specified in Section 217.388.

e) Instead of complying with the requirements of subsections (a), (b), (c) and (d) of this Section, an owner or operator may install and operate a CEMS on an affected unit that meets the applicable requirements of 40 CFR 60, subpart A and appendix B, or 40 CFR 75, incorporated by reference in Section 217.104, and complies with the quality assurance procedures specified in 40 CFR 60, appendix F or 40 CFR 75, as incorporated by reference in Section 217.104, or an alternate procedure as approved by the Agency or USEPA in a federally enforceable permit. The CEMS must be used to demonstrate compliance with the applicable emissions concentration or emissions averaging plan only on an ozone season and annual basis.

f) The testing and monitoring requirements of this Section do not apply to affected units in compliance with the requirements of the low usage limitations pursuant to Section 217.388(a)(3) or low usage units using NO_x allowances to comply with the requirements of this Subpart pursuant to Section 217.392(c), unless such units are included in an emissions averaging plan. Notwithstanding the above circumstances, when, in the opinion of the Agency or USEPA, it is necessary to conduct testing to demonstrate compliance with Section 217.388, the owner or operator of a unit must, at his or her own expense, conduct the test in accordance with the applicable test methods and procedures specified in this Section within 90 days after receipt of a notice to test from the Agency or USEPA.

(Source: Amended 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

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

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

225.325 Trading Program

SUBPART D: CAIR NO_x ANNUAL TRADING PROGRAM

Section
225.400 Purpose
225.405 Applicability
225.410 Compliance Requirements
225.415 Appeal Procedures
225.420 Permit Requirements
225.425 Annual Trading Budget
225.430 Timing for Annual Allocations
225.435 Methodology for Calculating Annual Allocations
225.440 Annual Allocations
225.445 New Unit Set-Aside (NUSA)
225.450 Monitoring, Recordkeeping and Reporting Requirements for Gross Electrical Output and Useful Thermal Energy
225.455 Clean Air Set-Aside (CASA)
225.460 Energy Efficiency and Conservation, Renewable Energy, and Clean Technology Projects
225.465 Clean Air Set-Aside (CASA) Allowances
225.470 Clean Air Set-Aside (CASA) Applications
225.475 Agency Action on Clean Air Set-Aside (CASA) Applications
225.480 Compliance Supplement Pool

SUBPART E: CAIR NO_x OZONE SEASON TRADING PROGRAM

Section
225.500 Purpose
225.505 Applicability
225.510 Compliance Requirements
225.515 Appeal Procedures
225.520 Permit Requirements
225.525 Ozone Season Trading Budget
225.530 Timing for Ozone Season Allocations
225.535 Methodology for Calculating Ozone Season Allocations
225.540 Ozone Season Allocations
225.545 New Unit Set-Aside (NUSA)
225.550 Monitoring, Recordkeeping and Reporting Requirements for Gross Electrical Output and Useful Thermal Energy
225.555 Clean Air Set-Aside (CASA)
225.560 Energy Efficiency and Conservation, Renewable Energy, and Clean Technology Projects
225.565 Clean Air Set-Aside (CASA) Allowances
225.570 Clean Air Set-Aside (CASA) Applications

225.575 Agency Action on Clean Air Set-Aside (CASA) Applications

SUBPART F: COMBINED POLLUTANT STANDARDS

225.600 Purpose (Repealed)
225.605 Applicability (Repealed)
225.610 Notice of Intent (Repealed)
225.615 Control Technology Requirements and Emissions Standards for Mercury (Repealed)
225.620 Emissions Standards for NO_x and SO_2 (Repealed)
225.625 Control Technology Requirements for NO_x, SO_2, and PM Emissions (Repealed)
225.630 Permanent Shut-Downs (Repealed)
225.635 Requirements for CAIR SO_2, CAIR NO_x, and CAIR NO_x Ozone Season Allowances (Repealed)
225.640 Clean Air Act Requirements (Repealed)
225.APPENDIX A Specified EGUs for Purposes of the CPS ~~Midwest Generation's~~ (Coal-Fired Boilers as of July 1, 2006)
225.APPENDIX B Continuous Emission Monitoring Systems for Mercury
225.EXHIBIT A Specifications and Test Procedures
225. EXHIBIT B Quality Assurance and Quality Control Procedures
225. EXHIBIT C Conversion Procedures
225. EXHIBIT D Quality Assurance and Operating Procedures for Sorbent Trap Monitoring Systems

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; amended in R15-21 at 39 Ill. Reg.________, effective______.

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 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 a 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 million) 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 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 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 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, 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), 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 the 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 (including 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;~~.~~ and

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 or devices installed and operating on the unit must notify the Agency of such change by January 1, 2017, or within 30 days after 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), or (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.

42) 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 ~~this~~ 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:

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

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

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 date~~s 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~~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 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___________)

Section225.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 BLR 71	Joliet 7
		72	Unit 7 Boiler BLR 72	Joliet 7
		81	Unit 8 Boiler BLR 81	Joliet 8
		82	Unit 8 Boiler BLR 82	Joliet 8
		5	Unit 6 Boiler BLR 5	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 BLR 17	Waukegan 6
		7	Unit 7 Boiler BLR 7	Waukegan 7
		8	Unit 8 Boiler BLR 8	Waukegan 8
Will County	197810AAK	1	Unit 1 Boiler BLR 1	Will County 1
		2	Unit 2 Boiler BLR 2	Will County 2
		3	Unit 3 Boiler BLR 3	Will County 3
		4	Unit 4 Boiler BLR 4	Will County 4

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

IT IS SO ORDERED.

Member Glosser dissented.

I, Don A. Brown, Assistant Clerk, Clerk of the Illinois Pollution Control Board, certify that the Board adopted the above opinion and order on October 1, 2015 by a vote of 4 to 1.

Don A. Brown

Don A. Brown, Assistant Clerk
Illinois Pollution Control Board