PETITIONER'S EXHIBITS

1) Sierra Club Comments prepared by Keith Harley, 34 pages (w/o exhibits)
2) Sierra Club Supplemental Comments prepared by Bruce Nilles, 27 pages
3) IEPA Dallman 4 Project Summary (undated), 22 pages
4) IEPA PSD Permit for Indeck-Elwood Project (Oct 10, 2003), 66 pages
5) USFWS and EPA consultation documents, 34 pages (including blank pages)
6) IEPA Dallman 4 Hearing Transcript, 74 pages

EXHIBIT 1

CHICAGO LEGAL CLINIC, INC.

South Chicago • Pilsen • Austin • Downtown

Rev. Thomas J. Paprocki, President
Edward Grossman, Executive Director
Marta C. Bukata, Deputy Director
Keith I. Harley
Veronique Baker
Greta Doumanian

Downtown Office
205 W. Monroe, 4th Floor
Chicago, IL 60606

Phone (312) 726-2938
Fax (312) 726-5206
TDD (773) 731-3477

May 22, 2006

Crystal Myers-Wilkins, Hearing Officer
Illinois Environmental Protection Agency
1021 N. Grand Ave., E.
P.O. Box 19276
Springfield, IL 62794-9276

Re: Draft Construction Permit/PSD Approval Springfield City Water, Light and Power Dallman Unit 4

To The Hearing Officer:

Please be advised that I represent the Sierra Club. The Sierra Club is a not-for-profit organization dedicated to protecting the environment and the health, welfare, and safety of the public. The Sierra Club has 25,000 individual members in Illinois who are directly affected by environmental quality in Illinois. These members include residents of Springfield, Illinois, who are organized into the Sangamon Valley Chapter of the Sierra Club. The Sierra Club has an active Clean Air Campaign focusing on the environmental and public health impacts of Illinois coal-burning power plants including the Springfield City Water Light and Power facility that is the subject of this permit proceeding.

Please accept this letter and the attached and referenced material as formal written comments by the Sierra Club regarding the draft Construction Permit/PSD Approval for Dallman Unit 4. In addition to these comments, other Sierra Club members and representatives are submitting supplemental written comments addressing the draft permit. In order to avoid unnecessary duplication, many of the documents referenced in these comments will be submitted for inclusion in the record with the supplemental comments submitted by Sierra Club.

In order to participate in the comment period for the draft Construction Permit/PSD Approval for Dallman Unit 4, Sierra Club acquired and reviewed the complete Illinois EPA permit file. Sierra Club also reviewed permit, operating and compliance records for the existing units at the Springfield facility, including current emissions information about Lakeside Units 7 and 8 that the permit applicant may close. A Sierra Club representative, Becki Clayborn, provided testimony at the March 22, 2006 public hearing.

Three Sierra Club Sangamon Valley Chapter members – Diane Lopez, Roger Ricketts and Carrie Kinsella - also testified, raising significant concerns about the impact of the proposed Dallman 4 unit on public health, as an impediment to the development of non-coal and cleaner IGCC alternatives, and as a contributor to global warming.

By way of summary, these comments will address several aspects of the draft permit that fail to meet minimal legal standards imposed under the PSD program. If the IL EPA fails to remedy these deficiencies in the final permit, it is the Sierra Club's determination that the final permit would violate PSD program requirements. Futhermore, in many of its decisions in the draft permit, the IL EPA is undercutting its ability to fulfill its obligations under the Clean Air Interstate Rule, the Clean Air Mercury Rule and new state implementation requirements under the 8 hour ozone and fine particulate standards.

I. Netting Exercise

The project proposes to net out of PSD review of NOx, SO2, and VOCs by shutting down Lakeside Units 7 and 8. The proposed netting has a number of problems set out below.

A. The Emission Reductions Are Not Contemporaneous

The netting analysis uses emission reductions from shutting down Lakeside Units 7 and 8 to offset emission increases from the new Dallman unit. An emission reduction must be contemporaneous with the proposed emission increase to be used in netting. 40 CFR 52.21(3)(i)(b). The draft permit does not require that the Lakeside units be shutdown until over 18 months after the new Dallman unit starts up and even then sets no firm time for shutdown.

A decrease is only "contemporaneous" with a proposed increase (i.e., the new Dallman unit) if it occurs between five years before construction commences and the date that the increase from the particular change occurs. 40 CFR 52.21(b)(3)(ii)(a) and (b). The increase from the particular change "occurs when the emissions unit becomes operational and begins to emit." 40 CFR 52.21(b)(3)(viii). A "shakedown period," not to exceed 180 days, is allowed for a replacement unit. *Ibid.* The draft permit does not comply with these requirements.

First, the application and the permit summary do not claim that new Dallman Unit 4 is a replacement for Lakeside Units 7 and 8. This is unlikely, as the new Dallman Unit is much bigger, 250 MW compared to a total of 75 MW for Lakeside Units 7 and 8. Thus, the new unit is not a replacement, and a shakedown exemption for emission increases is not allowed.

Second, even assuming the new Dallman unit were a replacement unit, the draft permit allows the 180 day shakedown period to be extended indefinitely. Permit, Condition 1.4. The Lakeside units are allowed to continue to operate during this extended shakedown period so long as NOx and SO_2 emission rates from both units are less than 420 and

2,580 tons per quarter. These emissions greatly exceed the PSD significance thresholds for both pollutants, triggering PSD review. Permit, Condition 1.5(a)(i).

Third, after the extended shakedown period, the draft permit allows a transition period for up to 18 months from the end of the extended shakedown period, during which the Lakeside units are allowed to continue to operate when the new unit is out of service for an extended outage. Permit, Condition 1.5(a)(ii). This represents a change in operation. The increase in emissions during this period would exceed the PSD significance threshold for all criteria pollutants, triggering PSD review for NOX and SO2.

B. The Emission Reductions Are Not Creditable

The proposed reductions would be obtained by shutting down existing Lakeside Units 7 and 8. The reductions must be credible to offset emission increases. 40 CFR 52.21(b)(3)(i)(*b*). The proposed reductions are not creditable because they are not enforceable as a practical matter and they are not based on the lower of actual or allowed emissions.

1. Reductions Are Not Enforceable As Practical Matter

A decrease in actual emissions is creditable only to the extent that "it is enforceable as a practical matter at and after the time that actual construction on the particular change begins." 40 CFR 52.21(b)(3)(vi)(*b*). The existing Title V Permit has not been revised to require that Lakeside Units 7 and 8 be shutdown by a date certain nor has an application been filed for such modification. Further, the draft PSD construction permit does not require the Lakeside units to be shutdown. In fact, the PSD permit "is issued based on the reduced operation and eventual shutdown" of these units. Permit Condition 1.5(a), p. 8. Thus, the reductions relied on in the netting exercise are not enforceable as a practical matter and cannot be relied upon to net out of PSD for any pollutant.

Under 35 Illinois Administrative Code 203.303(a), which is part of the State Implementation Plan, emission offsets must be effective prior to start-up of the new or modified source and must be federally enforceable by permit

2. Reductions Based On Actual Rather Than Allowable Emissions

The emission reductions from shutting down the Lakeside units were calculated based on average 2002 and 2003 actual emissions as reported to Clean Air Markets. However, a decrease is creditable only to the extent that "[t]he old level of actual emissions or the old level of allowable emissions, whichever is lower, exceeds the new level of actual emissions." 40 CFR 52.21(b)(3)(vi)(*a*). The allowable NOx emissions are lower than the actual NOx emissions used in the netting calculation. Thus, the allowable emissions should have been used. As demonstrated below, if allowable emissions are used in the netting, the increase in NOx from Dallman Unit 4 exceeds the PSD significance threshold.

The existing Title V permit contains a condition that limits NOx emissions from the two Lakeside units to 0.25 lb/MMBtu during the ozone season. Title V Permit, Condition 7.1.4(f)(i)(A), p. 30. The allowable NOx emissions based on allowed NOx emissions, rather than actual NOx emissions, are calculated in Table 1.

Table 1
Emissions Used For Netting
Lakeside Units 7 and 8

Period	Actual NOx[a] (ton)	Actual NOx[a] (lb/MMBtu)	Allowed NOx[b] (ton)	Allowed NOx[c] (lb/MMBtu)
2002 Ozone	650.4	0.92	176.7	0.25
2002 Nonozone	564.4	0.95	564.4	NL
2002 Total	1214.8	0.94	**741.1**	NL
2003 Ozone	540.5	0.91	148.5	0.25
2003 Nonozone	769.2	0.91	769.2	NL
2003 Total	1309.7	0.91	**917.7**	NL
2004 Ozone	124.0	0.89	34.8	0.25
2004 Nonozone	789.1	0.85	789.1	NL
2004 Total	913.1	0.86	**823.9**	NL
2005 Ozone	502.6	0.88	142.8	0.25
2005 Nonozone	693.8	0.97	693.8	NL
2005 Total	1196.4	0.93	**836.6**	NL

[a] Clean Air Markets.
[b] Calculated from actual as: (actual ozone season NOx tons)(allowed lb/MMBtu)/(actual lb/MMBtu).
[c] Allowed NOx emission limit from Title V Permit, Section 7.1.4(f)(i)(A), p. 30. NL = no limit.

The netting analysis the draft permit relied on (Permit, Attach. 4 & App., Appx. E) used average actual NOx emissions of 1,262 ton/yr, based on 2002 and 2003 (1214.8 and 1309.7 ton/yr) emissions as reported to the Clean Air Markets. Ap., Appx. E, Table 4. Table 1 shows the average allowed emissions are 829 ton/yr, based on 2002 and 2003 operations (741.1 and 917.7 ton/yr ton/yr). The allowed emissions must be used because they are lower than actual emissions.

The project would emit 1070 ton/yr. Other contemporaneous increases amount to 53.4 ton/yr from new diesel engines (39.4 ton/yr) and the proposed spray dry system (14.0 ton/yr). Permit, Attach. 2, Table 2-B. Thus, the netting analysis:

Project	1070 ton/yr
Reductions	829 ton/yr
Increases	53 ton/yr
Net Change	**294 ton/yr**
PSD Threshold	40 ton/yr

The net change in NOx emissions of 294 ton/yr exceeds the significance threshold of 40 ton/yr, triggering PSD review for NOx.

C. The Use of An Improper Baseline Improperly Affects NO_x calculation

The draft permit incorrectly concludes that CWLP will net out of PSD review for NO_x. In performing the netting exercise, CWLP did not follow the proper regulatory requirements at Step 5, where the source must determine the amount of each contemporaneous and creditable emissions increase and decrease for each pollutant. 1990 New Source Review Workshop Manual, P. A.48.

Specifically, CWLP did not use the correct period for determining the baseline actual emissions in establishing the creditable decreases attributable to the decommissioning of Lakeside Units 7 & 8. When the Illinois regulations are properly followed and the correct period is considered, the net change of NO_x rises significantly, from a net decrease of 138 tpy to a **net increase** of 69.3 tpy. This increase exceeds the significant emissions rate of 40 tpy, thus triggering PSD review. 35 IAC 203.209(a)(2).

CWLP chose to calculate baseline actual emissions using the average of years 2002 and 2003. While 40 CFR 52.21(48)(i) defines baseline actual emissions as "the average rate, in tons per year, at which the unit actually emitted the pollutant during **any consecutive 24-month period selected by the owner or operator** within the 5-year period immediately preceding when the owner or operator begins actual construction of the project," Illinois has promulgated its own definition, contained in the State Implementation Plan, that must be followed.

Illinois regulations define actual emissions as the average rate, in tons per year, at which the emissions unit actually emitted the pollutant during **the two-year period which immediately precedes the particular date** or such other period which is determined by the Illinois Environmental Protection Agency to be representative of normal source operation. 35 IAC 203.104. The regulations use the term "particular date" on a number of occasions (202.104, 203.104) without defining it, as does the federal regulation at 40 CFR 52.21(b)(21)(ii). However, the definition of "baseline actual emissions" under the federal regulations (40 CFR 52.21(48)(i)) uses a "period immediately preceding when the owner or operator begins actual construction of the project" as a starting point for determining the baseline. An online Illinois EPA guidance document on PSD supplies examples for creditable increases and decreases. Regarding creditable decreases, the examples provide that reduction credit is "based on the last 2 years of actual data prior to retirement." http://www.epa.state.il.us/air/new-source-review/new-source-review-part-3.html.

Using the standard of the two years immediately preceding the beginning of construction, **or** the two years prior to retirement, as the particular date, the 2002-2003 period used in the draft permit would not be correct in determining the baseline actual emissions. The correct years used to calculate the baseline should be 2004-2005. As the following tables illustrate, when the correct period is used, NO_x levels will exceed the major modification threshold, requiring PSD review.

Table 1 - Yearly NO_x Emission Levels (in tpy)*

Year	NO_x emissions levels
2002	1214.7
2003	1309.6
2004	1196.3
2005	913.10
2002-2003 avg.	1262.15
2004-2005 avg	**1054.7**

*Yearly values from http://www.epa.gov/airmarkets/emissions/prelimarp/index.html

Table 2 – Netting Calculations with Correct Period

Period	Total Emissions Increase	Decrease: Lakeside Units	Net Change in Emissions	Major Modification Threshold
2002-2003	1124	1262	-138	40
2004-2005	1124	**1054.7**	**+69.3**	40

The 'total emissions increase' value includes emissions from the proposed projected (1170 tpy) plus other contemporaneous increases (new diesel engines: 39.4 tpy & proposed spray dry system: 14.0 tpy). Draft permit, Attachment 2, Table 2-B. A net increase of 69.3 tpy is above the significant emissions rate of 40 tpy, and thus NO_x should be subject to PSD review. Neither CWLP nor IL EPA has provided any reason why the 2002-2003 period is "more representative" than the most recent two years. CWLP should amend their application in order to follow the correct regulatory requirements.

D. Effects of CAIR on Netting Exercise and Creditable Decreases

NSR Workshop Manual (October 1990) Step 4 (4) – "A source cannot credit for a decrease that it has had to make, **or will have to make,** in order to bring an emissions unit into compliance." (emphasis added).

According to the permit applicant itself, the Lakeside units will have to be decommissioned because of their age, condition and in order to achieve compliance with new regulations that originate in the Clean Air Act. Under these circumstances, the IL EPA should disallow any request for emission credits from the Lakeside units.

The permit applicant has freely acknowledged that the Lakeside Units must be decommissioned in order to achieve compliance. During the public hearing, CWLP's Regulatory Affairs Manager, William Murray, admitted that in order to comply with new regulations, the Lakeside Units must be decommissioned. Hearing Transcript PP 25-26. Mr. Murray stated:

25-26: I'd like to talk now a little bit more about the Dallman 4 project as it was alluded to by the agency. One element in this project is retirement of Lakeside 7 and 8. Again, these are uncontrolled units for the most part in terms of the major pollutants that we have to consider with existing clean air requirements and the requirements that we know are coming down the road; most specifically, the mercury rules, whether it be the federal rule or the proposed state rule, and the CAIR rule which is going to require further reductions of NOx both on an annual basis and an ozone season basis starting in 2009 and further reductions of SO2 starting in 2010 and actually down even further on both of those pollutants in 2015. So we are faced with this decision of what to do with the Lakeside units, and the logical conclusion that we came to from a technical and economical standpoint, the age of the units, they're going to be 50 years old soon, was that they retire them.

In an August, 2005 letter to the Lake Michigan Air Directors Consortium, which attached to these comments and labeled as Sierra Club Exhibit One, Mr. Murray underscored the need to decommission the Lakeside Units in order to achieve compliance with near term regulatory initiatives. In page 6 of this letter, Mr. Murray indicates: "The first conclusion reached was that continued operation of Lakeside units without controls would require the utilization of a substantial number of banked allowance and eventually the purchase of allowances for both SO2 and both NOX programs to balance the projected allocations and emissions. Given the age and size of the Lakeside units, it is not economically feasible to add the control equipment necessary to obtain the required emission reductions from CAIR." Later in this letter, Mr. Murray acknowledges the decision to decommission the Lakeside units does not necessarily lead to constructing any new unit, stating: "The Lakeside units will be retired and, *one scenario* would have these units replaced by a new unit..." Murray letter, page 8, emphasis added.

In a November 12, 2003 Memorandum to Springfield Alderman, CWLP General Manager Todd Renfrow stated:

New generating capacity is needed to replace Lakeside Units 6 and 7, which are nearing the end of their useful life. Efficiency of these units is low, meaning they take about 20% more coal to make a KWH than Dallman Unit 33. Without the proper pollution control equipment, sulfur dioxide and nitrogen oxide emissions are about 10 times higher from Lakeside in comparison to Dallman Unit 33. New emissions regulations would require a major investment to operate these units beyond 2009.

Mr. Renfrow's memorandum is attached to these comments and labeled as Sierra Club Exhibit Two.

Because the uncontrolled Lakeside units will be decommissioned in order to achieve compliance with new regulations, it is not appropriate for the resulting emission decreases to be used as credits for any new unit.

E. The SO2 Netting Analysis Fails To Consider Contemporaneous Increases

When any emissions decrease is claimed, as from shutting down Lakeside Units 7 and 8, all source-wide creditable and contemporaneous emission increases and decreases of the pollutant subject to netting must be included in the PSD applicability determination. 40 CFR 52.21(b)(3)(ii); NSR Manual, Sec. III B; Appx.E, P.1. The SO2 netting analysis did not include all contemporaneous emission increases.

First, in April 2002, CWLP requested that IL EPA modify its permits for the Lakeside and Dallman plants to increase the plant-wide SO2 cap from 2.304lb/hr. See - *Letter from S. David Farris, City, Water Light and Power, to Donald Sutton, IL EPA, April 19, 2005*, on Sierra Club CD submitted with supplemental comments. The current Title V permit indicates that this change was made. Title V Permit, Section 7.1.4.c, on page 29. This is a source-wide creditable contemporaneous potential emission increase and must be included in the netting analysis. This change in emission limit effectively increases potential SO2 emissions from the facility by much more than the decrease from shutting down Lakeside Units 7 and 8, thus triggering PSD review for SO2.

Second, the sulfur content of the fuel proposed for Dallman Unit 4 (6.96lb SO2/MMBtu) is higher than the sulfur content of the fuel that has been historically burned (,6.0 lb SO2/MMBtu) based on IL EPA's enforcement files. (See also - Dallman Unit 4 contract on CD submitted with Supplemental Sierra Club comments, Freeman Design Fuel Analysis. The facility must be designed to burn fuel with sulfur up to 6.53 lb SO2/MMBtu). This higher sulfur fuel would be burned facility-wide, tus allowing increases in SO2 emissions from Dallman Units 1 and 2 that were not considered in the netting analysis.

Third, the Clean Air Markets data for Dallman Units 1 and 2 indicates that the firing rate increased in 2004-2005 compared to prior years. This suggests a modification of these units or a cange in method of operation may have occurred prior to 2004-2005 which would allow emission increases. IL EPA must investigate this matter and require PSD review if warranted.

II. BACT Analysis of CWLP

A. The NOx Limit Does Not Meet The Appropriate BACT Standard

According to the draft permit, this plant was not subject to PSD with respect to NOx. CWLP demonstrated in a netting exercise that NOx emissions would decrease from the shutdown of the Lakeside facility. The current emissions rate of NOx at the Lakeside facility is 1,262 tons; CWLP showed that the potential emissions of NOx are 1,070 tons. This is a decrease of 152 tons.

However, there have been a substantial mistakes in the netting exercise done in CWLP's PSD Application. Correctly applied, the increase in NOx emissions is above the applicable significant emissions rate of 40 ton/yr set by the PSD rules. With this increase, the project would be subject to PSD emissions of NOx. NOx BACT should

consider the 0.05 lb/MMBtu 24-hour average limit contained in the Louisville Gas & Electric Trimble permit issued by the Commonwealth of Kentucky. There is substantial information that lower NOx rates are achieved. For example, the Clean Air Markets database indicates that in 2005 Havana unit 9 in Illinois had an annual NOx rate of 0.04 lb/MMBti. See http://www.epa.gov/airmarkets/emissions/prelimarp/05q4/054_il.txt. If the rate is calculated from the tons and firing rate on the same page the limit is even lower- (566.4 ton)(2000 lb/ton)/34,306,236 MMBtu = 0.033lb/MMBtu.
Thus, a "top down" BACT analysis should be prepared for NOx and new emission limits should be determined with consideration being given to control technology. A revised permit should be drafted to show such limits and BACT as required by PSD. With the issuance of a revised draft permit, a public review and comment period should be required.

B. Lower PM Filterable and PM Total Limits Can be Achieved And Should Be Required

The draft permit sets BACT emission limits on total PM of 0.035 lb/MMBtu and PM filterable of 0.015 lb/MMBtu based on a 3 hour block average. Permit, p. 10, Condition 2.1.2(b)(i)(B). Yet, the draft permit also states that "a lower limit (as low as 0.018 lb/MMBtu) may be set pursuant to Condition 2.1.15, which requires reevaluation of the [PM filterable] limit based upon actual PM_{10} emissions of the affected boiler." Permit, p. 10, Condition 2.1.2(b)(i)(B). The permitted control BACT technology for the reduction of total PM is a fabric filter baghouse and wet electrostatic precipitator. The baghouse is the selected BACT for filterable PM. There are two concerns with the permitted PM levels.

First, lower filterable PM limits can be achieved with a baghouse. Sierra Club does not take issue with the use of a baghouse for the control of filterable PM and total PM. However, lower emission limits can be achieved for these pollutants than are contained in the draft permit. Below is a list of facilities, their permitted PM limits, BACT technology used, facility output, and type of coal used. The permits for the following facilities have lower PM filterable or total limits than those proposed for CWLP:

- Newmont Nevada Energy Investment, NV: PM_{10} 0.012 lb/MMBtu (1-hr block)
    - Fabric Filter baghouse
    - 200 MW facility; sub-bituminous coal
- Indeck-Elwood, IL: PM total: 0.015 lb/MMBtu (3-hr block)
    - Fabric Filter Baghouse
    - 660 MW_e gross facility; circulating fluidized bed (Illinois coal)
- Longview Power, LLC, WV: PM total: 0.018 lb/MMBtu (6 hour rolling average)
    - Dry solid injection with fabric filter and wet scrubber
    - 600MW, pulverized coal (bituminous)
- Intermountain Power Generating Station- Unit 3: PM filterable: 0.0130 lb/MMBtu

- Fabric Filter Baghouse
  - 950 MW-gross; bituminous or blend
- Wygen 2, Wyoming: PM filterable: 0.012 lb/MMBtu
  - Fabric filter Baghouse
  - 500 MW; bituminous
- Trimble County Generating Station: PM (filterable and condensable) 0.018 lb/MMBtu. Permit, p. 73, Condition 2.a.
  - Fabric Filter Baghouse and WESP
  - 750 MW; bituminous

All of the above facilities were permitted at a rate that is lower then the permitted rate for Dallman. Specifically, Intermountain Power Generating Station- Unit 3 ("Intermountain") and Wygen 2 both have filterable PM limits that are considerably lower than those permitted for Dallman. These plants, like Dallman, both use a fabric filter as BACT and utilize bituminous coal. Dallman's draft permit should be revised to reflect the lowest permitted filterable PM limits.

In lowering the filterable PM limits, the PM total limit should also be lowered, as the total PM limit encompasses the filterable PM limit. Trimble is particularly comparable to Dallman Unit 4 because they are both permitted to burn bituminous coal and Trimble also proposes to use a baghouse along with a WESP. At a minimum, Dallman Unit 4 should be permitted to emit no more than 0.018 lb/MMBtu of total PM.

The second concern with the limits set for PM is that a lower limit may be based upon reevaluation. The draft permit suggests "a lower limit (as low as 0.018 lb/MMBtu) may be set pursuant to Condition 2.1.15, which requires reevaluation of the [PM filterable] limit based upon actual PM_{10} emissions of the affected boiler." However, with a complete BACT analysis,

> "the most stringent...alternative is established as BACT unless the applicant demonstrates, and the permitting authority in its informed judgment agrees, that technical considerations, or energy, environmental, or economic impacts justify a conclusion that the most stringent technology is not 'achievable' in that case." 1990 NSR Manual, p. B.2.

It appears, then, that "the most stringent alternative" would set the emission limits for total PM no higher than 0.0180 lb/MMBtu. As described above, 0.0180 lb/MMBtu (and lower) is not only an achievable limit for PM total, but it has also been achieved by other facilities and specified as BACT by the IL EPA and other permitting agencies for other coal-fired power plants.

Additionally, a lower PM filterable limit should be set to ensure that the total PM is able to reach the lower standard. Dallman Unit 4's PM filterable emission limit is not currently permitted to reflect the lowest possible emissions achievable from the chosen BACT.

Furthermore, in establishing permit limits based solely on performance after initial startup, the draft permit is allowing the facility discretion (unlawfully) to pollute at limits that are higher than necessary. The way the draft permit is currently written, Dallman Unit 4 has no incentive to lower PM limits because its only reward will be stricter emission standards. Thus, the emission limits for filterable and total PM should be permitted at the lower levels, with no reevaluation period.

C. Lower Filterable PM Emissions Have Been Achieved And Should Be Required

The permit sets a filterable PM emission limit of 0.015 lb/MMBtu based on a 3-hour block average. Permit, Condition 2.1.2.b(i)(A), p. 10. This limit is not BACT for filterable PM as set out below.

1. Permit Limits And Stack Tests

The application states that "ESPs and baghouses can reduce filterable PM10 emissions to 0.015 lb/MMBtu. This emission limit has been selected as BACT in several projects to fire high sulfur fuels and is among the most stringent filterable PM10 emission limits for large utility PC-fired boilers." Ap., p. 5-13. Elsewhere, the applicant asserts that 0.015 lb/MMBtu is the most restrictive filterable PM/PM10 limit proposed for a PC boiler firing high sulfur coal. 6-24-05 Murray Letter, p. 10.

This approach to setting the filterable PM/PM10 limit is not consistent with the definition of BACT, which is an emission limit based on the maximum degree of reduction that is achievable. The applicant only looked very narrowly, restricting its determination to other PC boilers fired on high sulfur coal. The availability of a control option for BACT depends on the characteristics of the gas stream and the capability of the technology. NSR Manual, p. B.19. Technology transfer must be considered in identifying control options. NSR Manual, p. B.11 "The fact that a control option has never been applied to process emission units similar or identical to that proposed does not mean it can be ignored in the BACT analysis if the potential for its application exists." NSR Manual, p. B.16.

There are many lower filterable PM/PM10 limits when one looks to this broader class of options. The key issues in making a BACT determination based on this data are the amount of particulate matter in the flue gas and the capability of the baghouse to remove it, not the sulfur content of the coal and the type of boiler. Sulfur content is irrelevant, as discussed below. The RBLC listing and other information[1] identifies the following similar sources with lower permitted filterable PM10 limits:

- 0.009 lb/MMBtu for Spurlock Unit 3
- 0.011 lb/MMBtu for JEA Northside 1 & 2
- 0.012 lb/MMBtu for Wygen II

[1] R. Andracsek and David Gaige, Particulate Emissions – Combustion Source Emissions Dependent on Test Method, 14th Inventory Conference, April 2005.

- 0.012 lb/MMBtu for Intermountain Power Unit

Two of these, Spurlock and JEA Northside, are circulating fluidized boilers ("CFBs") that burn high sulfur coals similar to Dallman. A CFB is a type of boiler that recirculates solids, creating a gas stream with roughly twice as much particulate as a PC boiler. Thus, a CFB represents a worst-case for PM control at Dallman Unit 4 because more particulate means a much higher control efficiency must be achieved by the baghouse. Thus, a more efficient baghouse would be required at these CFB than for Dallman Unit 4, all else being equal. In other words, these low filterable PM limits are more easily achievable at Dallman 4 because it has lower inlet PM concentrations. Of these, the JEA Northside facility has been constructed and tested at 0.0041 lb/MMBtu while burning a 50:50 blend of petroleum coke and Pittsburgh 8 coal[2] and at 0.004 lb/MMBtu while burning 100% Pittsburgh 8 coal.[3]

Many stack tests have been conducted at other facilities that indicate that much lower filterable PM limits are achievable. The NSR Manual indicates that performance tests are one of the sources that should be considered in identifying control technology alternatives. NSR Manual, p. B.11. The applicant and IL EPA did not evaluate any performance tests. Performance tests for a number of additional facilities indicate that coal-fired boilers routinely meet much lower PM filterable emission rates than proposed as BACT for this facility.

The state of Florida maintains a searchable source test database. We obtained all PM/PM10 performance tests for that state's coal-fired power plants. The Florida database contained 225 tests that measured PM or PM10 at less than 0.015 lb/MMBtu, the PM/PM10 BACT limit proposed for Springfield. Of these, 65% or 147 recorded PM/PM10 emissions less than 0.01 lb/MMBtu and 36% or 82 recorded PM/PM10 emissions less than 0.005 lb/MMBtu.[4]

Similar results have been reported for coal-fired power plants in other states. Several of Georgia Power's coal-fired units equipped with ESPs have achieved lower PM/PM10 emission rates, including: 0.003 lb/MMBtu at Scherer Unit 4 in 1998;[5] 0.004 lb/MMBtu at Scherer Unit 4 in 2000;[6] 0.006 lb/MMBtu at Yates Unit 7; 0.008 lb/MMBtu at Yates Unit 6[7] and Hammond Unit 4;[8] 0.010 at Scherer Unit 3 in 1998; and 0.011 at Scherer Unit 3 in 2000. A recent published article also reported four performance tests for coal-

[2] Black & Veatch, Fuel Capability Demonstration Test Report 2 for the JEA Large-Scale CFB Combustion Demonstration Project, 50/50 Blend Petroleum Coke and Pittsburgh 8 Coal Fuel, U.S. Department of Energy, December 3, 2004.

[3] Black & Veatch, Fuel Capability Demonstration Test Report 1 for the JEA Large-Scale CFB Combustion Demonstration Project, 100% Pittsburgh 8 Fuel, U.S. Department of Energy, September 3, 2004.

[4] Florida PM/PM10 Performance Tests on Coal-Fired Power Plants With Emissions Less Than 0.015 lb/MMBtu, May 25, 2004.

[5] Spectrum Systems Inc., Compliance Particulate Emissions Testing Performed at Georgia Power Company Plant Scherer Units 1, 2, 3 and 4, Juliette, Georgia, 1998.

[6] Spectrum Systems Inc., Compliance Particulate Emissions Testing Performed at Georgia Power Company Plant Scherer Units 1, 2, 3 and 4, Juliette, Georgia, 2000.

[7] Spectrum Systems Inc., Compliance Particulate Emissions Testing Performed at Georgia Power Company Plant Yates Units 6 and 7, Whitesburg, Georgia, 2001.

[8] Spectrum Systems Inc., Compliance Particulate Emissions Testing Performed at Georgia Power Company Plant Hammond Unit 4, Coosa, Georgia, 1998.

fired power plants in New Jersey and Utah that ranged from 0.0045 lb/MMBtu to 0.0126 lb/MMBtu.[9]

Therefore, clearly, much lower PM/PM10 emission rates have been permitted and achieved than the 0.015 lb/MMBtu proposed as BACT for Dallman Unit 4. The BACT analysis should be revised to the lowest level achievable, as evidenced by the numerous stack tests referenced above, or CWLP must explain why lower PM limits discussed are not BACT for Dallman Unit 4. This explanation should be based on physical, chemical, and engineering principles related to the gas stream and the capability of the control technology, not irrelevant and unsupported statements about sulfur content of the fuel and the type of boiler.

2. Margin of Compliance

The IL EPA ignores this considerable record of lower filterable PM emission limits and tests, arguing that the proposed 0.015 lb/MMBtu limit "provides an appropriate margin of compliance to address the normal variability in performance of a baghouse...and to address the additional variability that may be present given the sulfur content of the coal supply to the boiler." Summary, p. 9. There are several problems with this margin of compliance argument.

First, IL EPA has not provided any information on the so-called margin of compliance. How big is it? What is the baseline against which it was determined? How was it determined? The public cannot comment on a margin if it is not identified and described. The data we summarize above suggest that the proposed filterable PM limit is at least three times higher than levels that have been achieved elsewhere (0.015/0.004 = 3.75), suggesting a margin of a factor of three, which is excessive for the reasons set out below. The IL EPA does not provide any information to support the need for such a large margin of compliance. Should the agency assert it has discretion to set BACT levels to accommodate a margin of compliance, the agency must explain the basis for its decision.

Second, IL EPA provides no evidence that the variability of the baghouse causes PM emissions to vary over a factor of three or any other factor. Particulate emissions from a well maintained baghouse should display little variability, as confirmed by long-term opacity data at Hayden.[10] If the permit conditions are met, there should be little variability in particulate emissions from the baghouse during routine operation. The permit requires that the baghouse be maintained in accordance with good air pollution control practices "to assure proper functioning of equipment and minimize malfunctions" (which cause variability). Condition 2.1.6.b.a(v), p. 17. The permit also requires the pressure drop across the baghouse to be monitored so that any deviations in operation can be identified and corrected. Permit, Condition 2.1.10.c(i)(B), p. 24. Thus, it makes no sense to set a margin of safety that assumes variations that are per se indications of

---

[9] Louis A. Corio and John Sherwell, In-Stack Condensible Particulate Matter Measurements and Issues, Journal of the Air & Waste Management Association, v. 50, February 2000, pp. 207-218.
[10] Technical Memorandum from Bern Hinckley and Todd Schmidt to Sierra Club, Re: Hayden Opacity Data after FFDC Retrofit, April 26, 2005.

noncompliance. The permit should encourage good air pollution control practices by setting an aggressive limit, not the other way around. The IL EPA has in essence jacked up the PM BACT limit to allow the baghouse to operate at less than optimal conditions. This is contrary to common sense and the definition of BACT.

Third, IL EPA argues that a margin of compliance is required to address "the additional variability that may be present given the sulfur content of the coal supply to the boiler" and "a lower BACT limit would not provide an adequate compliance margin given the coal supply for the boiler." Summary, p. 9. The record we reviewed does not contain any information that could be used to assess coal quality variability and IL EPA pointed to none in support of its margin argument. This would require large numbers of measurements over a several year period. The record only contains the design, or worst-case coal quality, and typical analyses, single numbers that reveal nothing about variability. Thus, this claim is unsupported.

Further, this claim is refuted by the applicant and irrelevant. The applicant explains that its coal is currently washed and will continue to be washed. "Washed coal is much more consistent in its overall quality. Typically washed coal may only vary 1 to 2 percent in total ash (i.e. 8 to 10%) whereas the raw coal delivered to the preparation plant might vary from up to 10 percent in total ash (i.e. 28 to 38% ash)." 6-27-05 Murray Letter, p. 7. The ash content is relevant to filterable PM as ash in the coal becomes fly ash in the flue gases. The fly ash is the particulate matter that is removed by the baghouse and subject to regulation. The sulfur content of the coal is irrelevant as to variability of PM emissions. A 1% to 2% variation in the inlet PM does not warrant a factor of three (300%) margin of safety, especially given the fact that the baghouse will be designed for the worst case particulate loading and thus de facto takes into account any variability in coal quality.

Finally, CWLP in their bid documents requested PM10 guarantees of 0.012lb/MMBtu filterable and 0.035 lb/MMBtu total for fuels and under all operating conditions from 40% to 100% load. They did not ask vendors how low they could go or what was achievable. *Burns & McDonnell, City Water Light and Power, Springfield, Illinois, New Generation Project, Contract 200, Electric Generation Unit, Bid Documents, December, 2004.* (This document is included on the CD separately submitted with other Sierra Club comments in the file entitled "Springfield RFP and Contract.") The contract that CWLP signed with the winning bidder, KBV, includes "limited guarantees".

An agency has discretion to base an emission limitation on a control efficiency that is "<u>somewhat</u> lower than the optimal level," but only under certain limited conditions. In re Masonite, 5 E.A.D. 551, 560 (EAB 1994). These conditions include: (1) where there is little experience with application of the technology to that type of facility; (2) the control efficiency is known to fluctuate; (3) past decisions involved different source types; and (4) the permit requires tests to be performed to determine optimum operating conditions for technology, which then has to be followed. None of these conditions apply to the proposed baghouse and filterable PM limit at Dallman Unit 4. Thus, IL EPA should require that Unit 4 meet a lower filterable PM limit, no higher than 0.004 lb/MMBtu.

D. Lower Total PM10 Emissions Have Been Achieved

The permit sets a limit on total PM, comprising the sum of filterable plus condensable, of 0.035 lb/MMBtu based on a 3-hour block average. Permit, Condition 2.1.2.b(i)(B), p. 10. This limit is assumed to consist of 0.010 lb/MMBtu of filterable PM and 0.025 lb/MMBtu of condensable PM. Summary, p. 10. The permit also indicates that a lower PM limit may be set, as low as 0.018 lb/MMBtu, based on an "evaluation." Permit, Condition 2.1.15, pp. 28-29. This limit is not BACT.

The IL EPA has it backwards. The record indicates that BACT is an emission limit no higher than 0.018 lb/MMBtu. The permit should establish this level as BACT, require that the control system be designed to meet it, and include an optimization study. If the BACT limit cannot be met in the optimization study based on appropriate design and best efforts, the permit should be reopened to establish a higher limit. This latter approach is commonly used to address uncertainty. See, e.g., the permits issued for KCPL's Hawthorne Unit 5 (MO) and Spurlock Unit 2 (KY). Similarly, should a lower limit actually be achieved during the optimization study then the permit limit should be revised downwards.

The permit summary notes that a total PM10 limit of 0.018 lb/MMBtu has been set in a number of recent permits, including those issued for Elm Road, Longview, Thoroughbred, and Plumb Point.[11] However, IL EPA argues that these lower limits do not establish an adequate basis to set a limit because none of these boilers are built and operating and the limit has not been "achieved in practice." Summary, p. 10. This is wrong on three counts.

First, the law does not require that a limit be "achieved in practice" to be BACT. The definition of BACT requires that emission rates be "achievable." 40 C.F.R. § 52.21(b)(12). The plain language, "achievable," rather than "achieved in practice" is the technology forcing component of BACT. "Achieved," on the other hand, means accomplished in the past. "Achievable" means capable of being accomplished in the future. BACT can only move pollution control technology forward if emission limits are set stringent enough to force companies to try new approaches and do something different from the "same old." See e.g., Alabama Power v. US EPA, 636 F.2d 323, 372 (D.C. Cir. 1980).

[11] We note that 0.018 lb/MMBtu has been more recently included in permits or proposed for the following facilities: City Utilities, Springfield, MO; Itan, MO; Seminole, FL; Weston Unit 4, WI; Further, total PM limits lower than the proposed 0.035 lb/MMBtu have been permitted elsewhere including Comanche, CO & MidAmerica, IA.

An "achievable" limit is only constrained by energy, environmental, and economic impacts and other costs." 40 C.F.R. § 52.21(b)(12). Nothing in the plain language of the definition of BACT contemplates eliminating candidate BACT limits because an emission rate has not been "achieved in practice." The BACT emission rate need only be "achievable," based on engineering judgment. *See also*, NSR Manual.

Second, the 0.018 lb/MMBtu limit has been recently proposed by applicants. See BACT analyses prepared for Seminole (FL) and Trimble (KY). Applicants consult with their engineers and vendors before proposing BACT limits. Thus, the fact that 0.018 lb/MMBtu is being proposed by applicants, not imposed by permitting agencies, indicates that owners and the market consider this limit to be achievable. It would not be proposed if owners could not get a guarantee for this limit.

Third, lower total PM limits than 0.035 lb/MMBtu have been both permitted and achieved in practice. These include the following:

- 0.0088 lb/MMBtu for Northampton
- 0.010 lb/MMBtu for Seward
- 0.018 lb/MMBtu for Hawthorn

See attached permits and stack tests. Two of these facilities are CFBs that burn high sulfur fuels. This is a worst case for PM control due to high inlet PM. All three facilities have been tested at lower PM emission rates than 0.018 lb/MMBtu. This test data includes the following:

- 0.0044 lb/MMBtu for Northampton in 2001
- 0.0012 lb/MMBtu for Northampton in 1995
- 0.0041 lb/MMBtu for Seward in 2005
- 0.0114 – 0.0170 lb/MMBtu for Hawthorn 2001-2004

Finally, the IL EPA relied on these same permits for unbuilt units to support its basis for sulfuric acid mist BACT. Summary, pp. 10, 12. In fact, IL EPA argued that SAM is the major components of condensables and because the same SAM limit is proposed for Dallman and these other units, condensable PM emissions would be comparable. Summary, p. 10. This argument leads to the conclusion that the total PM limit should be 0.015 lb/MMBtu (0.010 + 0.005). Regardless, it would appear that IL EPA can't have it both ways. These recent permit limits either are an adequate basis for setting both PM and SAM limits or they are not. They cannot be an adequate basis for SAM and an inadequate basis for PM.

E. The Sulfuric Acid Mist Limit Is Not BACT

The draft permit sets a BACT limit for SAM of 0.0050 lb/MMBtu, based on a 3-hour block average. Permit, Condition 2.1.2.b(iii), p. 11. The IL EPA states with no support that this "is a stringent limit that is in line with the BACT limits set for other recently permitted new coal-fired utility boilers." Summary, p. 12. "In line with" does not satisfy the definition of BACT, which is an emission limit based on the maximum degree of reduction that is achievable. The applicant also claims that this emission limit "is consistent with sulfuric acid mist limits from recently permitted units." Ap., p. 5-20. However, neither points to any supporting data or explains the basis of this limit, precluding meaningful public review. The proposed SAM limit is not BACT for several reasons as set out below.

First, the top down BACT analysis (NSR Manual, Sec. III) for SAM in the application is incomplete. The first step of the top down process is to identify all available control options. The application and permit summary only identify three control options: co-removal during scrubbing, the use of a wet electrostatic precipitator ("WESP"), and sorbent injection. Summary, p. 11; Ap., Sec. 5.9.1. There are other feasible options that can be used to control SAM, including a low SO_2 to SO_3 conversion SCR catalyst,[12] lowering the temperature across the SCR catalyst using more frequent soot blowing,[13] a more efficient SO_2 scrubber (such as the Chiyoda bubbling jet reactor), regenerating the SCR catalyst rather than replacing it,[14] and combinations of these control options.[15]

A significant fraction of the SAM is created by the SCR, which is proposed to control NOx. The SCR catalyst converts SO_2 created in the boiler to SO_3, which subsequently combines with water to form SAM.[16] The applicant admitted that the SCR catalyst can convert 0.5% to 3% of the SO_2 to SO_3 and that conversion rates of less than 1% are feasible, but claimed "this will also reduce the catalyst reactivity for the reduction of NOx." 6-27-06 Murray Letter, pp. 12-13. The applicant failed to mention that reduced catalyst reactivity is overcome by using a more reactive catalyst formulation or modifying the catalyst management plan.[17]

The applicant did not disclose the proposed SO_2 to SO_3 conversion rate for the SCR catalyst that would be used at Dallman Unit 4, preventing meaningful commentary on the proposed limit. The achievable SAM emission limit depends directly on this factor, which should have been disclosed and considered in the SAM BACT analysis. Sulfuric acid mist emissions can be reduced by well over 50% by using a low SO_2 to SO_3 conversion catalyst, e.g., 0.5% instead of 3%. Low conversion SCR catalyst was not considered in the application, even though it is widely used to control SAM emissions.

---

[12] J. Cooper and others, First Application of Babcock-Hitachi K.K. Low SO_2 to SO_3 Oxidation Catalyst at the Petersburg Generation Station, ICAC 2005; Low SO_2 Oxidation Rate for Hitachi Catalyst, FGD & DeNOx Newsletter, No. 293, September 2002; Morita and others, Development and Operating Results of Low SO_2 to SO_3 Conversion Rate Catalyst for DeNOX Application.

[13] Rick Lausman, Impacts of Plant Operations on Opacity and Particulate Emissions, Black & Veatch, July 28, 2005.

[14] D.W. Bullock and others, Full-Scale Catalyst Regeneration Experience at the Coal-Fired Indiantown Generating Plant, DOE 2003 SCR/SNCR Workshop; M. Cooper, New Life for Old Catalyst, Power Engineering, March 2006.

[15]; K. Dombrowski and others, SO_3 Mitigation Guide and Cost Estimating Workbook, Mega 2004; AEP, General James M. Gavin Plant, Feasibility of Alternative SO_3 Plume Mitigation Strategies, June 1, 2002;

[16] R.K. Srivastava and others, Emissions of Sulfur Trioxide from Coal-Fired Power Plants, J. Air & Waste Manage. Assoc., v. 54, 2004, pp. 750-762.

[17] J. Cooper and others, First Application of Babcock-Hitachi K.K. Low SO_2 to SO_3 Oxidation Catalyst at the Petersburg Generation Station, ICAC 2005.

However, Sierra Club obtained a copy of the May, 2006 contract to build the new Dallman Unit. This contract, signed in October, 2005 – long before the draft permit was issued – shows that the vendor has guaranteed a maximum 0.5% SO2 to SO3 conversion catalyst. *See: CD submitted separately with other Sierra Club comments, file "Springfield RFP and Contract," page PDF 2399.*

The application states that the wet FGD for Dallman Unit 4 is expected to remove only about 50% of the SO_3. Ap., p. 5-18. Although this is a standard default value for a conventional limestone forced oxidation scrubber ("LSFO"),[18] many vendors of conventional wet FGD systems will not guarantee 50% SAM control. The applicant should be required to disclose the type of SO_2 scrubber that will be used and the guaranteed SAM removal efficiency, if any, in support of its proposed SAM BACT emission limit. Other types of scrubbers achieve higher SAM removal efficiencies. These include the Chiyoda bubbling jet reactor.[19] These alternatives, including more effective SAM control technologies, should be evaluated in the top down BACT analysis.

Second, the BACT analysis does not rank the control technologies by effectiveness, the third step of a top down analysis. The only supporting evidence we found for the proposed SAM limit is a partial printout from the RACT/BACT/LAER Clearinghouse (Ap., Table D-7) and the National Coal-Fired Utility Spreadsheet (Ap., Table D-8). These two sources of information include SAM emission limits that are lower than proposed for Dallman Unit 4. These include:[20]

- 0.002 lb/MMBtu for SEI Birchwood
- 0.0042 lb/MMBtu for MidAmerican Energy
- 0.0046 lb/MMBtu for Prairie Energy Corn Belt Energy.

The record does not explain why these lower limits identified by the applicant do not establish BACT for Dallman Unit 4. A justification should be provided for rejecting the most stringent emission limits.

If lower sulfur coal is advanced as the excuse for ignoring these lower limits, the BACT analysis should be expanded to include the consideration of lower sulfur coal, which is required based on the definition of BACT. 40 CFR 52.21(b). See Sierra Club's Supplemental Comments for additional discussion of low-sulfur coal.

[18] Southern Company, An Updated Method for Estimating Total Sulfuric Acid Emissions from Stationary Power Plants, Revised March 2003, Table 3.
[19] Black & Veatch, Wisconsin Public Service Weston Unit 4, Flue Gas Desulfurization, System Analysis, April 2003.
[20] See RBLC SAM table and supporting permit information on the attached CD for these and following cites to lower limits.

The applicant also failed to include several sources listed in the RBLC that have lower SAM limits than proposed for Dallman Unit 4. These are:

- 0.001 lb/MMBtu for TS Power
- 0.0015 lb/MMBtu for Parish Unit 8
- 0.0014 lb/MMBtu for Santee Cooper Cross
- 0.004 lb/MMBtu for Parish Units 5-7
- 0.0045 lb/MMBtu for Manitowoc

The BACT information sources relied on by the applicant, the RBLC and EPA spreadsheets are inadequate because reporting is not mandatory and frequently lags permitting. Thus, one must look further to other sources to establish BACT including other permitting authorities, source tests, technical literature, vendors, etc. A more detailed search indicates that lower sulfuric acid mist emission limits have been set in other permits that were not found by the applicant or included in the applicants' sources. These include:

- 0.0010 lb/MMBtu for Newmont
- 0.0024 lb/MMBtu for AES Puerto Rico
- 0.004 lb/MMBtu for Trimble

The record, which did not identify these lower limits, is thus silent as to why they do not establish BACT for Dallman Unit 4. Further, Sierra Club notes that CWLP in its bid documents requested and will receive a guarantee for 0.004lb/MMBtu. CWLP did not ask how low the vendors were willing to go or what was achievable. *See bid documents on CD in Sierra Club comments.*

The above 11 permits demonstrate that lower SAM emission limits have been required than proposed for Dallman Unit 4. No explanation is offered why the draft permit does not demand lower limits. Although the coals burned by these various units have different amounts of sulfur, the applicant has asserted in its analysis of low sulfur coal that "Dallman Unit 4 stack emissions of sulfuric acid mist, filterable PM10, and CO would be the same regardless or (sic) whether Illinois coal or a low sulfur coal were combusted by Dallman Unit 4." 6-27-04 Murray Letter, p. 7. Regardless, calculations set out below indicate that Dallman Unit 4 could achieve these lower SAM limits permitted elsewhere.

Third, the record does not explain how the limit of 0.005 lb/MMBtu was derived. It simply appears, followed by the claim that other facilities have been permitted at that level, without pointing to a single one. The achievable SAM emission limit depends upon many factors, including the sulfur content of the coal, the type of boiler, the type of SO_2 scrubber, the type of particulate control device, the design removal efficiency of the WESP, the type of air preheater, the type of SCR catalyst, etc. The record contains none of this information for Dallman Unit 4. Thus, the record contains no basis for eliminating the lower SAM limits identified above or for setting the high limit proposed in the draft permit.

The SAM BACT limit is typically calculated using the Southern Company method[21] and unit-specific assumptions as detailed above. These unit specific assumptions are generally part of the BACT determination. This record contains no such analysis or the data required to perform it. Thus, we calculated SAM emissions assuming worst-case coal (6.96 lb SO_2/MMBtu) and default removal efficiencies for the air preheater, fabric filter, and scrubber. Our calculations, included in the SAM spreadsheet on the Sierra Club CD, indicate that the proposed facility should be able to achieve a SAM emission rate of 0.0024 lb/MMBtu, conservatively assuming worst-case coal (which would be burned infrequently), 0.5% SO_2 to SO_3 conversion across the SCR (based on the vendor guarantee), 50% SAM removal in the scrubber (>70% is achievable using the Chiyoda JBR and 99% using dry FGD), and 97% SAM removal in the WESP (based on the vendor guarantee). *See CD submitted separately with other Sierra Club comments, page pdf 2400.* A limit of 0.001 lb/MMBtu is achievable using a 0.5% conversion SCR catalyst and a 90% efficient WESP.

Thus, the draft permit does not require BACT for SAM. The permit should be revised to reflect the lowest achievable SAM limit, no greater than 0.024 lb/MMBtu, which includes a generous safety factor.

F. The Use of Low Sulfur Coal Should Be Included In Determining BACT

Please see Sierra Club's Supplemental Comments for more on this issue.

G. Startups and Shutdowns Are Improperly Excluded

The draft permit is not clear on what the emissions limits are applicable during periods of startup, shutdown and malfunction. First, the draft permit indicates that the emissions for startup, shutdown and malfunction for PM filterable and PM will be addressed in 2.1.2(e). Permit, p. 10, Condition 2.1.2(b)(1). However, there is no condition 2.1.2(e). The limits for PM filterable and PM are only addressed in Attachment 1, Table 1-A. It appears that periods of startup, shutdown and malfunction are excluded from all emission limits except those limits expressed as tons per year. Permit, p. 1-1, Attachment 1. Thus, the periods are excluded from BACT for PM filterable, PM, CO, and Sulfuric Acid Mist.

BACT emissions limits must be met on a continual basis at all levels of operation. Emissions can be higher during startups and shut downs because the pollution control equipment may not operate at peak efficiency or may not operate at all. Startups and shutdowns are part of the normal operation and the emissions that occur during these periods should be included in the BACT analysis and limited in the permit. Additionally, restrictions on what constitutes a startup, shutdown, and malfunction and how long each process is allowed to exceed the limits should also be addressed. *In re Tallmadge Energy*

[21] Southern Company, An Updated Method for Estimating Total Sulfuric Acid Emissions from Stationary Power Plants, Revised March 2003, Table 3.

Center, Order Denying Review in Part and Remanding in Part, PSD Appeal No. 02-12 9EAB May 21, 2003) sip op. at 24.

The draft permit contained no evidence that there was consideration to eliminate or reduce excess emissions during startup and shutdown, beyond the specification of plans that would be developed in the future. Permit, p. 16, Condition 2.1.6(a)(ii). The emissions elimination/reduction analysis has been left to the permittee to be conducted in the future, without any approval. This is not acceptable under the CAA. Tallmadge, slip op at 26-27; RockGen, 8 E.A.D. 536, 551-555. The permit should include the design, control, and methodological, or other changes that are appropriate for inclusion to minimize allowed excess emissions during startup and shutdown. Without such information, enforcement is impossible.

The IL EPA should also take note that the startup provisions it has inserted into this permitting process are not legally adequate. The draft permit's terms are inconsistent with the EPA guidance regarding excess emissions during malfunctions, startup and shutdown. See Kathleen M. Bennett, Memorandum "Policy on Excess Emissions During Startup, Shutdown, Maintenance, and Malfunctions," September 28, 1982 ("Bennett Mem."-copy enclosed and labeled as Sierra Club Exhibit Three); Steven A. Herman and Robert Perciasepe, Memorandum "State Implementation Plans: Policy Regarding Excess Emissions During Malfunctions, Startup, and Shutdown," September 20, 1999 ("Herman Mem." – copy enclosed and labeled as Sierra Club Exhibit Four).

Automatic exemptions for excess emissions during startup are prohibited. Bennett Mem. at 1. "[A]ll periods of excess emissions are violations of the applicable standard." Id. EPA is particularly intolerant of excess emissions during start-up and shutdown. "Start-up and shutdown of process equipment are part of the normal operation of a source and should be accounted for in the design and implementation or the operating procedure for the process and control equipment. Accordingly, it is reasonable to expect that careful planning will eliminate violations of emission limitations during such periods." Id. at 3.

EPA does give the states some discretion, however, to forego enforcement actions for some instances of excess emissions. At the state's discretion, sources are permitted to make a demonstration that excess emissions were due to an unavoidable occurrence in order to preclude an enforcement action. Id. at 1. However, state discretion is limited in this context to (1) refraining from taking an enforcement action under circumstances when excess emissions were caused by events entirely beyond the control of the owner or operators; (2) excusing a source from penalties in the context of an enforcement action for excess emissions if the source can demonstrate that it meets certain criteria (an "affirmative defense"); and (3) providing such an affirmative defense in actions for penalties but not in actions for injunctive relief. Herman Mem. at 1-2. States may not excuse or authorize excess emissions that would otherwise be violations of applicable emission limitations.

The draft permit authorizes operation "...in violation of the applicable state emission standards...during startup." Such language must be revised so that it is clear that excess emissions during these periods are still violations. Further, such startup conditions must be revised to make clear that this affirmative defense is available only in actions for penalties and not in actions for injunctive relief.

EPA policy requires that a permittee must demonstrate that "all reasonable efforts have been made to minimize startup emissions, duration of individual startups and frequency of startups." Herman Mem., Attachment "Policy on Excess Emissions During Malfunctions, Startup, and Shutdown." More specifically regarding excess emissions during startups, EPA policy indicates that States must require of permittees that: (1) Any bypass leading to excess emissions be unavoidable and necessary to prevent loss of life, personal injury, or severe property damage; (2) The facility be operated in a manner consistent with good practice for minimizing emissions; (3) All possible steps be taken to minimize the impact of excess emissions on ambient air quality; (4) All emission monitoring systems be kept in operation if at all possible; and (5) The permittee properly and promptly notify the Agency. Herman Mem., Attachment "Policy on Excess Emissions During Malfunctions, Startup, and Shutdown."

For this affirmative defense be available, a permittee must be required to demonstrate its adherence to the above requirements and a permittee must demonstrate that: (1) Periods of excess emissions during startup and shutdown were short, infrequent and could not have been prevented through careful planning and design; and (2) Excess emissions were not part of a recurring pattern indicative of inadequate design, operation or maintenance. Herman Mem. Attachment "Policy on Excess Emissions During Malfunctions, Startup, and Shutdown."

Finally, a permittee's actions in response to excess emissions must be documented by a properly signed, contemporaneous operating log. Herman Mem. Attachment "Policy on Excess Emissions During Malfunctions, Startup, and Shutdown."

The misuse of the startup/shutdown exemption is clearly needed in this case based on a review of opacity exceedances at the CWLP facility. A summary of these exceedances, based on CWLP's own self-reporting, is attached to these comments and labeled as Sierra Club Exhibit Five. As this analysis reveals, CWLP will operate units for many hours despite excess opacity, claiming these several hour periods are "start up." Illinois law allows the IL EPA to take into account the operating history of the permit applicant. Under 415 ILCS 5/39(a), the Agency "may impose reasonable conditions specifically related to the applicant's past compliance history with this Act as necessary to correct, detect or prevent noncompliance." In the present case, this dictates that IL EPA strictly limit the ability of the permit applicant to operate in start up and, correspondingly, to claim that protracted periods of excess emissions can be excused based on an overly broad exemption.

The BACT analysis must be revised to set strict limits that include periods of startup or shutdown, or expanded to set separate, verifiable limits that apply during periods of startup and shutdown.

The permit terms regarding excess emissions during malfunction must be revised to include a definition of malfunction. As used in the draft permit, malfunction is vague and renders the condition not practically enforceable. The following definition of malfunction should be included: "a sudden and unavoidable breakdown of process or control equipment." Herman Mem. Attachment "Policy on Excess Emissions During Malfunctions, Startup, and Shutdown." More specifically regarding excess emissions during malfunctions and breakdowns, U.S. EPA policy indicates that States must require of permittees that: (1) The air pollution control equipment and processes be maintained and operated in a manner consistent with good practice for minimizing emissions; (2) Repairs be made in an expeditious fashion when the operator knows or should know that applicable emission limitations are being exceeded; (3) Amount and duration of excess emissions be minimized to the maximum extent practicable; (4) All possible steps be taken to minimize the impact of excess emissions on ambient air quality; and (5) All emission monitoring systems be kept in operation when possible. Herman Mem., Attachment "Policy on Excess Emissions During Malfunctions, Startup, and Shutdown."

For this affirmative defense to be available, a permittee must be required to demonstrate its adherence to the above requirements and must be required to demonstrate that: (1) The excess emissions were caused by a sudden, unavoidable breakdown of technology, beyond the control of the owner or operator; (2) The excess emissions (i) did not stem from any activity or event that could have been foreseen and avoided, or planned for, and (ii) could not have been avoided by better operation and maintenance practices; and (3) The excess emissions were not part of a recurring pattern indicative of inadequate design, operation, or maintenance. Herman Mem. Attachment "Policy on Excess Emissions During Malfunctions, Startup, and Shutdown."

Finally, the permittee's actions in response to excess emissions must be documented by a properly signed, contemporaneous operating log. Herman Mem. Attachment "Policy on Excess Emissions During Malfunctions, Startup, and Shutdown."

H. CO- Good Combustion Control is Not Defined

The draft permit lists "good combustion control" as BACT (presumably for CO). Permit, p. 10, 2.1.2(a)(i). The term "good combustion control" is not defined within the permit and thus is not enforceable. Combustion controls include a wide range of techniques, including staged combustion, excess air, low-NOx or ultra low-NOx, and combustion optimization systems. By simply using the term "good combustion control", it is left up to the facility to determine what this entails. The permit should be revised to define the term "good combustion control". Without specification of a technology, enforcement of BACT is impossible.

III. Incomplete Analysis of the Impact Of Increased Emissions On Threatened and Endangered Species

The Indiana Bat is mentioned as a species potentially threatened by the proposed Springfield Power Plant Modification Project in a letter from the U.S. Fish and Wildlife

Service to Burns and McDonnell dated 9/14/04. The letter is in reply to Burns and McDonnell's form request for information relating to endangered species that might be impacted by the proposed project. Burns and McDonnell is the environmental consultant to CLWP for the boiler construction project. The letter lists the Bald Eagle (Threatened) and the Indiana Bat (Endangered) as residing within the potential deposition range of power plant emissions. These correspondences are attached and labeled as Sierra Club Exhibit Six.

Of interest concerning the Indiana Bat is that female bats form nursery colonies in "pealing or loose" tree bark and that the bats in general "roost" in trees during the summer. See Sierra Club Exhibit 7. Because the proposed boiler will emit an estimated combined total of 561 tons of particulate matter (PM), and this represents a significant increase over reported PM emissions from Lakeside, a determination should be made if there is the likelihood of a taking within the meaning of the Endangered Species Act. A taking could occur because of a probable accumulation on neighboring trees that may adversely affect the bat's natural habitat. If there is the possibility of a taking, the permit applicant should be required to determine the nature and extent of the harm to the Indiana Bat and, if necessary, to seek an incidental taking permit and/or institute a habitat conservation plan. EPA has failed to comply with its ESA consultation obligations. See Sierra Club's Supplemental Comments for more on compliance with the federal ESA.

The superficial consultation in the present case also fails to meet the minimal requirements imposed under the Illinois Endangered Species Act. The reply letter regarding Illinois state threatened or endangered species dated 8/25/04 to the Burns and McDonnell's inquiry lists no Illinois endangered or threatened species within a "1 mile radius" of the proposed new boiler. It does not appear any further consultation has taken place under the Illinois Endangered Species Act. This consultation is legally inadequate.

The Illinois Administrative Code Section 1075.30(a), which implements the consultation process states in part, "Any construction, land management or other activity authorized, funded or performed by a State agency or local unit of government that will result in a change to the existing environmental conditions and/or may have a cumulative, direct or indirect adverse impact on a listed species or its essential habitat or that otherwise jeopardizes the survival of that species and/or may have a cumulative, direct or indirect adverse impact on a Natural Area shall be evaluated through the consultation process." The administrative code further states that "the proposed action shall not commence until the completion of the consultation process. (17 Ill Adm. Code Section 1075.40). This mandate has not been fulfilled in light of the very limited consultation, which does not address impacts beyond a one mile radius, does not address direct and indirect impacts, does not address cumulative impacts and, on its face, is inconsistent with the U.S. FWS determination that both an endangered and threatened species have habitat in areas that could be impacted by substantially increased PM emissions from the CWLP facility.

IV. Inadequate HAP Emission Control at Dalman Unit 4

The draft permit subjects the proposed unit to control mercury, hydrogen chloride and VOM emissions (p,11) effective within 9 months of the boiler startup as follows:

Mercury	Carbon injection	or	95% removal efficiency (p.11)
Hydrogen Chloride	0.020 lb/million Btu	or	97.5% removal efficiency (p.13)
VOM	0.0036 lb/million Btu		

However, the draft permit does not propose HAP limits that are even close to what the permit applicant in its application acknowledges the unit can achieve. In certain instances, the new Unit of itself will be a greater HAP emitter than the entire existing CWLP facility.

The majority of space dedicated to HAP emissions in the draft permit deals only with testing. On page 18 the draft permit states that independently commissioned tests shall be made after the first 60 days of operation to determine emissions of VOM, hydrogen chloride, fluorides, mercury and "other metals" and again between 5 and 9 months after commencing operation (p.19) and again within 45 days if requested by the IL EPA. Within 2 years the draft permit requires testing for Dioxin/Furon emissions (p.20) according to specified EPA methods. The metals mercury, arsenic, beryllium, cadmium, chromium, lead, manganese and nickel are specified for testing. Mercury emissions are required to have continuous monitoring.

The draft permit requires annual emission reports in accordance with 35 IAC Part 254 forwarded to the EPA for at least the following 10 HAPs: hydrogen chloride, hydrogen fluoride, mercury, arsenic, beryllium, cadmium, chromium, lead, manganese, nickel (p.54).

The boiler Emission Limitation Table in the permit includes the following HAPs.

VOM	(38.4 tpy)	
Fluorides	(2.6 tpy)	[decrease from present emissions below]
Lead	(0.22 tpy)	[no change in present emissions below]
Hydrogen Chloride	(76.5 tpy)	
Mercury	(0.023 tpy)	[in excess of permit application of 0.017 tons/py]

For comparison purposes, the following averaged HAP air emissions listed on the EPA Toxic Release Inventory were emitted from the entire CWLP facility over the past 3 years:

Hydrochloric Acid	(295 tpy)
Hydrogen Fluoride	(16.613 tpy)
Lead Compounds	(0.22 tpy)
Manganese	(0.263 tpy)
Mercury Compounds	(0.013 tpy)

Sulfuric Acid	(171.8 tpy)
Vanadium Comp.	(0.027 tpy)
Zinc Compounds	(2.6 tpy) [2002 only]

See Toxic Release Inventory report available at:
http://oaspub.epa.gov/enviro/tris_control.tris-print?tris_id=62707CTYWT3100S
(Toxic Release Inventory report for City Water Light & Power City of Springfield).

Moreover, the draft permit application of 2004 lists the following estimated HAP emissions many of which are not listed in the permit Emission Limitation Table:

Antimony	(0.01 tpy)	
Arsenic	(0.22 tpy)	
Beryllium	(0.01 tpy)	
Cadmium	(0.03 tpy)	
Chromium	(0.14 tpy)	
Chromium IV	(0.04 tpy)	
Cobalt	(0.05 tpy)	
H2SO4	(53.4 tpy)	
Lead	(0.22 tpy)	[equal to present emissions and permit table]
Manganese	(0.26 tpy)	[equal to the present emissions above]
Mercury	(0.017 tpy)	[less than the draft permit limit]
Nickel	(0.15 tpy)	
Selenium	(0.68 tpy)	
VOC[M]	(38.4 tpy)	[equal to Emission Limitation Table]

The allowable mercury emission limit in the draft permit (0.023 tons/py) is significantly higher than either the permit application (0.017 tons/py) or the presently reported air emissions from the entire CWLP facility, as averaged over the past three years (0.013 tons/py). For other HAPs, the new unit's permitted emissions appear to equal the emissions for the entire CWLP facility. Because only Lakeside is proposed to be decommissioned, this is evidence that the new unit and the still operating units will cumulatively emit significantly higher levels of hazardous air pollutants. Under these circumstances, there is a requirement for a qualitative health and welfare equivalency demonstration that has not been conducted as part of the permit review for this facility. (*see* U.S. EPA New Source Review Manual, A.38-39).

Additionally, the HAP limits proposed in the permit application but not listed in the permit Emission Limitation Table should be subject to limits in the final permit.

V. MATERIAL HANDLING

The project emits PM and PM10 from equipment used to handle, convey, and store materials including coal, limestone, gypsum, fly ash, and bottom ash. The material handling equipment includes a truck unloading system, transfer towers, a coal stackout system, an underground coal reclaim system, silos, enclosures of various types vented to baghouses, and storage piles. Some of this equipment is new and some is existing sources that will be either modified, or used at a higher rate.

The application does not include a top-down BACT analysis for the material handling equipment. Instead, the application asserts with no support that certain levels of control or control options constitute BACT. In other instances, the BACT analysis and draft permit are wholly silent on BACT and one must dig through the emission calculations to figure out what was assumed for purposes of air modeling.

A. Material Handling BACT Control Technology Determinations

This section discusses material handling control technology determinations. These are presumably the BACT technology determinations. The next section discusses the emission limits set for this equipment, which we also presume are the BACT emission limits. We say presume because the draft permit does not state that either the technology determinations or the emission limits are set pursuant to BACT. However, a comparison of the draft permit with the application suggests that these technology determinations and limits were set pursuant to BACT . We suggest that the permit be clarified throughout to identify the BACT limits.

This section discusses control technology determinations for each type of material handling source, e.g., those controlled with baghouses, to track the organization in the permit.

1. PM Emissions From Dry Material Collected And Vented To A Baghouse

Many material handling transfer points are enclosed, the dust is collected, and vented to baghouses. For these sources, the draft permit sets a BACT PM limit of 0.01 grains per dry standard cubic foot ("gr/dscf"). Permit, Conditions 2.2.2(b)(ii) and 2.2.2(d)(ii), pp. 31-32.

a. BACT Limit

The baghouse BACT determination is based on the application, which asserts with no support that "[t]he industry "standard" for baghouse outlet emission rates is 0.01 grains per dry standard cubic foot (gr/dscf)." Ap., pp. 5-20/21. BACT is not the industry standard, but rather, an emission rate based on the maximum degree of reduction that is achievable. The application does not contain a responsive BACT analysis.

The IL EPA challenged the applicant's original BACT determination for these sources, 0.02 gr/dscf, and demanded a detailed justification as to why a more stringent BACT limit was not selected. In response, the applicant produced a table summarizing BACT limits for material handling dust collectors permitted since year 2000. The applicant then lowered the proposed BACT limit from 0.02 to 0.01 gr/dscf, asserting based on this table, that "it was determined that an emission limit of 0.01 gr/dscf is an appropriate emission limit for the dust collectors to be used for Dallman Unit 4." 6-27-05 Murray Letter, p. 13.

However, the table does not support the applicant's claim. The applicant does not explain why it believes 0.01 gr/dscf is an appropriate limit. This is particularly baffling given that the proffered table includes grain loadings that are lower than 0.01 gr/dscf. The lower limits reported by the applicant include:

- 0.004 g/dscf for coal and limestone collectors at the Elm Road facility
- 0.005 g/dscf for coal and limestone collectors at the MidAmerican facility
- 0.009 g/disc for coal collectors at the Wygen 2 facility.

Further, the IL EPA itself has issued a permit for a coal-fired boiler that includes essentially identical enclosures vented to baghouses. The permit limit for these baghouses is no more than 0.005 gr/dscf. Indeck-Ellwood permit, Condition 2.2.a(i), p. 26.

Thus, BACT for PM/PM10 for material handling operations vented to a baghouse should be a grain loading of no more than 0.004 gr/dscf.

We note that the emission calculations were not based on grain loadings, but rather AP-42 emission factors and control efficiencies for the dust collectors. Ap., Appx. C, Material Handling Calculations. The assumed dust collector control efficiency in these calculations, 99%, is also not BACT. Dust collectors can achieve 99.99% PM control. The files we reviewed do not contain gas flow rates through the baghouses. Thus, it is not possible to determine if the PM emission rates calculated from AP-42 emission factors and control efficiencies (the emissions used in the modeling) are consistent with the BACT determination in the draft permit as a grain loading. The application should be supplemented to supply design flow rates for all collectors so emissions can be calculated from the reported grain loadings.

b. Enforceability

BACT limits must be practically enforceable, which means monitoring must be required to assure that they are met. The grain loading limit for the material handling baghouses is not enforceable as a practical matter because the draft permit does not require any testing to determine if the limit is ever met. Permit, Condition 2.2.8, pp. 34.-37 The only performance testing required for material handling equipment is initial testing to determine compliance with NSPS limits. Testing for all other emission conditions, including grain loading of baghouses, is conducted only at the request of the IL EPA. Permit, Condition 2.2.8-2(b), p. 36. The permit should be revised to require testing of all baghouses subject to BACT grain loading limits on startup and subsequently, at least once every five years.

<u>2. PM Emissions from Storage Piles of Dry Material</u>

An inventory of coal and limestone are maintained in storage piles. The draft permit establishes BACT for these piles as no visible emissions, determined by EPA Method 22, or a nominal control efficiency of 90% for coal and 99% for limestone. Permit, Condition 2.2.c(ii), p. 31. The application concludes that BACT for these piles is wet suppression using water and/or chemical surfactants. Ap., p. 5-21. The applicant apparently made this choice as it claims elsewhere that the RBLC does not list any other specific controls for fugitives open sources. 6-27-04 Murray Letter, p. 14.

The file we reviewed contains no BACT analysis that supports either of these proposed limits. Permits have required additional measures to control fugitive dust from storage piles. Other controls are available, including pile compaction, cover materials, enclosures, wind screens, and weekly inspections. See, e.g., the Elm Road permit. A BACT analysis should be prepared for storage piles of dry material and the proposed limits modified accordingly.

These limits are also not practically enforceable as the draft permit requires no monitoring to determine either visible emissions or control efficiencies.

3. PM Emissions Conveyors And Drop Points

The draft permit does not contain any BACT control technology determinations for conveyors and drop points. Permit, Condition 2.2.2. While Condition 2.2.6, p. 34, requires that the drop distance be minimized, this is only one way of controlling drop emissions, is not listed in the control technology section, and does not appear to be based on a BACT analysis. The application also does not contain a BACT analysis for conveyors and drop points. Ap., Sec. 5.10. Some of the subject transfer points are part of the existing Dallman Units 31-33 coal transfer system. Ap., p. 3-9. However, since the project will increase the amount of coal processed through this system, it is subject to PM BACT.

A BACT analysis should be performed to evaluate controls for all conveyors and drop points, both new facilities and existing facilities. This analysis should consider enclosed conveyors, underground transfer with no ventilation (no emissions), dustless transfers, minimizing drop height, low pressure drops, treating coal with a chemical suppressant prior to transfer, and dry fogging systems. See, e.g., the Comanche Generating Station Coal Storage and Handling Permit.

VI. Material Handling PM Emission Limit

The draft permit sets an emission limit of 11.8 ton/yr for all material handling operations combined. Compliance is determined using a rolling 12 month average, calculated from the amount of material handled and emission factors. Permit, Condition 2.2.7, p. 34. The draft permit further requires that the PM emission rates in Table B-1 be met. Permit, Condition 2.2.11.b(iv), p. 39. These limits are not enforceable as a practical matter.

These emissions rates (Permit, Table 1-B) were calculated using emission factors from AP-42 and assumptions about the amount of material handled and PM control efficiency. Ap., Sec. 3.1 and Appx. C. The draft permit does not require any independent verification of these emissions, or of the factors and assumptions that were relied on to convert the emission factors into emission rates. In fact, compliance is determined using the same emission factors used to calculate the Permit limits, which is a self serving prophecy. Permit, Condition 2.2.11.b(v), p. 39.

The EPA has noted that AP-42 emission factors are not an adequate basis for determining compliance, *viz.*, "...emission factors, such as those in EPA's AP-42 compilation, are based upon the average of the values from available testing, and are not generally recommended as the approach to characterizing emissions from any given source for purposes of applicability determination....the EPA has not changed its position that such emission factors are not an acceptable approach for large industrial facilities."[22] You cannot determine compliance with an emission rate (those in Table 1-B) by simply repeating the calculation used to derive the rate in the first place. The rate, in pounds per hour or tons per year, must be confirmed by testing the pollutants in the emission stream or verifying the factors used in the calculation.

Typical emissions factors fail to capture variations of equipment operations and cannot ensure compliance with hourly emissions limits if, for example, the unit does not operate properly or an air pollution control device malfunctions or wears out or is different in any way from the class of units used to derive the emission factor. One cannot confirm that the project's emissions are consistent with PM emissions that were modeled or ensure that the project consistently meets its hourly and annual PM emission limits without testing the emission streams.

The Permit must be revised to require testing to confirm the emission factors and calculation procedures used to estimate the emission rates in Table 1-B. The permit should also be revised to require the factors used in the emission calculations, amount of material process and control efficiency, be recorded and reported.

VII. HAUL ROADS

Trucks will be used to haul coal, limestone, ammonia, fly ash, bottom ash, gypsum, and brine solids. Trucks suspend dust on the haul road surface and shoulders of the road, creating fugitive PM10 emissions. As discussed in the modeling comment, these fugitive emissions are the main contributor to ambient PM10 concentrations because they are released near ground level.

A. Haul Road BACT

[22] See, e.g., Memorandum from John S. Seitz and Eric Shaeffer, to Addressees, Re: Potential to Emit (PTE) Guidance for Specific Source Categories, April 14, 1998.

The control technology determination section of the draft permit requires "good air pollution control practices," which include paving and treatment sufficient to achieve 90% dust control. Permit, Condition 2.4.2.a(i), p. 48. This language is too general and ambiguous to enforce and is not BACT for several reasons.

First, the applicant stated in response to an IL EPA inquiry that the only controls identified in the RBLC are water spray and vacuum sweeping. Thus, the applicant proposed water spray and vacuum sweeping for new paved haul roads at up to one hour intervals, or as conditions warranted, depending upon the road segment. 6-27-05 Murray Letter, p. 14. The applicant's BACT determination (as to frequency of application for various haul roads) is not included in the draft permit and should be since it is more restrictive than the permit.

Second, the applicant limited its search for haul road fugitive dust controls to BACT determinations reported in the RBLC and thus failed to specify BACT-level controls. The RBLC is only one of several sources that should be considered to make a BACT determination. NSR Manual, p. B.11. There are many other haul road mitigation measures that should have been considered and required as BACT, including the use of dust suppressants, prompt removal of materials deposited on the roadway, covering of open trucks transporting material likely to become airborne, salting/sanding for snow and ice conditions, paving or otherwise stabilizing the shoulders of haul roads, and use of wind breaks to prevent wind erosion from adjacent areas.[23] The BACT determination and permit should require the use of these additional fugitive dust control measures.

Third, the 90% nominal control stipulated in the draft permit is inconsistent with the assumptions used to calculate PM10 emissions from these roads as used in the dispersion modeling. As discussed below, the draft permit should require at least the same level of control as assumed in the dispersion modeling. The emission calculations assumed 96% PM10 control for new plus existing trucks on entrance roads and 94% PM10 control for the ammonia, ammonia loop, brine solids, and brine solids loop roads. Ap., Appx. C, Haul Road Emission Calculations – Rev. 1. Thus, even assuming the emission calculations are based on BACT levels of control, the draft permit does not assure that these levels are actually met.

Fourth, the record we reviewed presents no evidence that the control efficiencies stated in the draft permit (90%) and assumed in the fugitive dust emission calculations (79% to 96%) will be met. The fugitive dust studies cited above suggest that additional mitigation measures are required to achieve the very high control efficiencies assumed in the fugitive dust haul road PM10 emission calculations.

---

[23] C. Cowherd and others, Control of Open Fugitive Dust Sources, EPA Report EPA-450/3-88-008, September 1988, Sec. 2.0; U.S. EPA, Fugitive Dust Background Document and Technical Information Document for Best Available Control Measures, Report EPA-450/2-92-004, September 1992, Sec. 3.0; C. Cowherd and others, Control of Fugitive and Hazardous Dusts, Noyes Data Corp. 1990; H. Hesketh and F.L. Cross, Jr., Fugitive Emissions and Controls, Ann Arbor Science, 1983.

Fifth, the draft permit does not require any demonstration that the 90% control efficiency stated in the permit will be achieved. Instead, it requires the development of a "written operating program" that describes the control measures that will be implemented. The program would be submitted to IL EPA for review and approval. Permit, Condition 2.4.6. This written program is part of the BACT determination and should have been included in the draft permit and circulated for public review.

B. Haul Road Emissions

BACT emission limits must "demonstrate protection of short term ambient standards (limits written in pounds/hour) and be enforceable as a practical matter (contain appropriate averaging times, compliance verification and recordkeeping requirements)." The modeled 24-hr PM10 concentration (149 $\mu g/m^3$) is very close to the standard (150 $\mu g/m^3$) and the increase in 24-hour PM10 due to the project alone (26.86 $\mu g/m^3$) is very close to the 24-hour Class II increment (30 $\mu g/m^3$). Ap., Table 6-3. The draft permit limits PM10 emissions from the haul roads to 6.0 ton/yr. Permit, Condition 2.4.7, p. 50. This blanket limit is not adequate to ensure the short term ambient standards are met and is not enforceable as a practical matter.

1. Ambient Standards Not Protected

This limit is the total PM10 emissions from all haul roads. Ap., Table 3-1 and Appx. C. The impact of haul road emissions on ambient standards varies depending upon the haul road segment, e.g., entrance, limestone, bottom ash, gypsum, fly ash, ammonia, etc. The entrance haul roads have the largest impact, followed by the coal haul roads. A very small increase in PM emissions from the entrance or coal haul roads, offset by an equivalent decrease in emissions from other haul roads, could cause exceedances of the 24-hour PM10 NAAQS and increment while complying with the 6.0 ton/yr limit. Thus, it is possible to meet the 6.0 ton/yr limit, but exceed the 24-hour PM10 ambient air quality standards. To prevent this, the permit should be modified to set separate PM10 emission limits on classes of haul roads to assure that ambient standards are met.

2. Haul Road Emission Limit Not Enforceable As Practical Matter

Practical enforceability means the source must be able to show continuous compliance with each limitation or requirement.[24] Adequate testing, monitoring, and record-keeping must be included in the permit. NSR Manual, pp. A.5-A.6.

First, the haul road emission limit of 6.0 ton/yr is a blanket emission rate expressed only on an annual basis. An inspector cannot verify compliance with an annual limit. An annual limit also does not limit emissions during the first year of operation. An appendix to the NSR Manual notes:

---

[24] *See, e.g.*, "Guidance on Limiting Potential to Emit in New Source Permitting," from Terrell F. Hunt, Associate Enforcement Counsel, OECA, and John Seitz, Director, OAQPS, to EPA Regional Offices, June 13, 1989.

> Compliance with any limitation must be able to be established at any given time. When drafting permit limitations, the writer must always ensure that restrictions are written in such a manner that an inspector could verify instantly whether the source is or was complying with the permit conditions. Therefore, short-term averaging times on limitations are essential.
>
> Emission limits should reflect operation of the control equipment, be short-term, and, where feasible, the permit should require a continuous emissions monitor. Blanket emissions limits alone (*e.g.*, tons/yr, lb/hr) are virtually impossible to verify or enforce, and are therefore not enforceable as a practical matter.

NSR Manual, pp. c.3–c.5.

The NSR Manual also includes a chapter on "Effective Permit Writing." This chapter explains that emission and operational limits "must be clearly expressed, easily measurable, and allow no subjectivity... Such limits should be of a short term nature, continuous and enforceable." NSR Manual, p. H.5. The haul road annual PM limit is a long-term blanket limit and is thus not enforceable as a practical matter. The permit should be revised to set short-term limits, including a limit for the first year.

Second, the fugitive PM10 emissions used in the air quality modeling are based on certain assumptions, set out in the Application, Appendix C. These include amount of material hauled, the type of trucks, the presence of paving, and a specific surface silt content. Some of these assumptions, are unlikely to be valid. For example, the emission calculations assume no increase in truck trips over the entrance haul roads, which were thus omitted from the PSD modeling. 6-27-05 Murray Letter, p. 14. It is not believable that truck trips on the entrance haul roads would not increase as a result of this project, given the substantial increase in coal, limestone, gypsum, and other materials that would move through the entrance. Further, it is unlikely that the silt content of surface roads is only 2 g/m^2, as assumed in haul road emission calculations. Both of these assumptions appear to have been chosen to reduce ambient 24-hour PM10 concentrations to just below the 24-hour NAAQS and Class II increment. Thus, it is very important that these and other assumptions used to estimate haul road PM emissions be verified by actual monitoring.

The draft permit does not require any emission testing, operational monitoring and measurement, or emission monitoring to determine compliance with the haul road emission limit of 6.0 ton/yr. Permit, Conditions 2.4.8, 2.4.9, 2.4.10. Thus, there is no assurance that the PM10 modeling accurately represents site conditions.

The draft permit does not require any demonstration that the haul road emissions will be less than or equal to those assumed in the dispersion modeling beyond a calculation. See supra, emission factors are not an acceptable basis for compliance demonstration. The Permit should be modified to require a study to measure the key variables used in the emission calculations (e.g., haul road length, number of truck trips, truck weight, haul road surface silt content).

The draft permit does not require any restrictions on the emission generating activity, i.e., truck trips over paved haul roads. The permit should be revised to limit the amount of material hauled to that assumed in the PM10 emission calculations.

Please contact me if you have any questions or require further clarification of these comments.

Sincerely,

Keith Harley
Attorney for Sierra Club

Enclosures

CC

Bharat Mathur
Acting Regional Administrator
U.S. EPA Region 5
77 W. Jackson Blvd.
Chicago, IL 60604

EXHIBIT 2

SIERRA CLUB
FOUNDED 1892

MIDWEST OFFICE - Madison
122 W. Washington Ave., Suite 830
Madison, Wisconsin 53703
(608) 257-4994
FAX (608) 257-3513
mw.field@sierraclub.org

May 22, 2006

Crystal Myers-Wilkins, Hearing Officer
Illinois Environmental Protection Agency
1021 N. Grand Ave., E.
P.O. Box 19276
Springfield, IL 62794-9276

Bharat Mathur
Acting Regional Administrator
US EPA Region 5
77 W. Jackson Blvd
Chicago, IL 60604

Re: Draft Construction Permit/PSD Approval – Springfield City Water, Light and Power, Dallman Unit 4

Dear Ms. Meyers-Wilkins and Mr. Mathur:

Please find enclosed Sierra Club's Supplemental Comments regarding the above-referenced draft PSD permit. Also enclosed are three disks containing cited material, modeling and meteorological data. These Supplemental Comments are in addition to the comments filed on behalf of Sierra Club by Keith Harley of the Chicago Legal Clinic. American Lung Association of Metropolitan Chicago also joins in both sets of comments. These comments were prepared with assistance from Dr. Phyllis Fox, Camille Sears, and John Purdum. Their resumes are attached as exhibit 1.

1. CWLP Failed To Make Vendor Responses Available

On April 17, 2006 Sierra Club sent CWLP a request pursuant to the Illinois Freedom of Information Act for, *inter alia*, "copies of all … vendor guarantees …, and all correspondence between CWLP and vendors for the proposed boiler and associated pollution control equipment." A copy of this request is attached as exhibit 2. In response CWLP made inches of printed material available, Sierra Club hired a copy service to scan the material, and send the disk to our expert. The disk did not include any vendor guarantees or other correspondence involving any companies beyond the vendor selected by CWLP. We had expected to receive: (1) all vendor proposals (2) the city's evaluation of vendor proposals; (3) correspondence between vendors and city; (4) cost estimates broken out down to basic components; and (5) correspondence between city and its permitting consultants. This material has not been made available as of the date of these comments.

Vendor guarantee information is an important source of information in developing BACT limits for each of the regulated pollutants, including sulfuric acid mist, PM/PM10, nitrogen oxides, and sulfur dioxide. Absent this information Sierra Club, and we submit IL EPA, is unable to determine whether lower BACT limits are achievable.

On this basis, Sierra Club and ALAMC request an extension of an additional twenty days after CWLP makes available the information requested in Sierra Club's April 17, 2006 FOIA request.

2. EPA Failed to Comply With the Federal Endangered Species Act

Under the Endangered Species Act, "Congress intended endangered species to be afforded the highest of priorities." *TVA v. Hill*, 437 U.S. 153, 174 (1978). Section 7(a)(2) directs each federal agency to consult with the Secretary of the Interior to ensure that any action which it authorizes, funds or carries out "is not likely to jeopardize the continued existence of any endangered species or threatened species or result in the destruction or adverse modification of habitat of such species which is determined by the Secretary...to be critical ...." 16 U.S.C. 1536(a)(2). There has been no consultation and no such determination in the present case.

Issuance of a PSD permit is a federal action subject to the ESA. *In re Dos Republicas Resources Co., Inc.* 6 E.A.D. 643, 649 (EAB, 1996); 40 C.F.R. 402.02 ("Action means all activities or programs of any kind authorized, funded, or carried out, in whole or in part, by Federal agencies in the United States.... Examples include...(c) the granting of licenses [or] permits..."). EPA agrees. *See* Brief of EPA Office of Air and Radiation filed in the Indeck-Elwood proceeding at 1, March 17, 2006. (PSD Appeal No. 03-04).

In addition to requiring meaningful consultation and prohibiting jeopardy, the ESA also directs agencies to use their authorities to conserve endangered species by proactive measures, typically manifest in the imposition of a habitat conservation plan. "It is further declared to be the policy of Congress that all federal departments and agencies shall seek to conserve endangered species and threatened species and shall utilize their authorities in furtherance of the purposes of this chapter." 16 U.S.C. 1531(c)(1). As the Environmental Appeals Board has explained, "[c]onservation activities seek to bring an endangered species back to an improved condition, further from extinction." *Dos Republicos*, 6 E.A.D. at 673; 16 U.S.C. 1523(3) (defining, *inter alia*, "conservation"). Sierra Club strongly opposes the issuance of a permit that would lead to an "irreversible or irretrievable commitment of resources with respect to the agency action which has the effect of foreclosing the formulation or implementation of any reasonable and prudent alternatives." 16 U.S.C. § 1536(d); *see* 50 C.F.R. § 402.09.

Consultation must be completed prior to issuance of a draft permit. There are at least three relevant sections of the CAA and PSD regulations: sections 160(5), 165(a)(2) and 40 C.F.R. Pt. 124. None of these provisions explicitly references the ESA; however, when read together, these provisions strongly indicate that the ESA and PSD permit proceedings must be coordinated closely. Additionally, to comport with the strict public participation and disclosure requirements contained in Part 124, an ESA consultation must be completed and included in the administrative record *before* a draft PSD permit is issued.

Section 160(5) states that the purpose of the PSD program is "to assure that any decision to permit increased air pollution in any area to which this section applies is made only *after* careful consideration of all the consequences of such a decision and *after* adequate procedural opportunities for informed public participation in the decisionmaking process." 42 U.S.C. § 7470(5) (emphasis added). Section 165(a)(2) builds on the section 160(5) public participation and disclosure requirements by requiring that a permitting authority provide the public with a public hearing at which it can offer testimony on a wide range of matters:

> No major emitting facility . . . may be constructed in any area to which this part applies unless—... (2) ... a public hearing has been held with opportunity for interested persons ... to appear and submit written or oral presentations on the air quality impact of such source, alternatives thereto, control technology requirements, and other appropriate considerations ....

42 U.S.C. § 7475(a)(2). Read together these statutory provisions require that before a public hearing is held for a proposed PSD source that a permitting agency make available to the public a reasonable degree of information about the impacts associated with a proposed PSD project, including any significant environmental issues, such as impacts on endangered species.

The PSD regulations governing the administrative record requirements for draft and final permits offer even stronger evidence that an ESA consultation must be completed before issuance of a draft PSD permit. For example, 40 C.F.R. § 124.8 requires that a permitting authority prepare a "fact sheet" for "every draft permit which the Director finds is the subject of wide-spread public interest or raises major issues." Such a fact sheet "shall briefly set forth the principal facts and the significant factual, legal methodological and policy questions considered in preparing the draft permit." *Id.* A draft permit must be based on the administrative record and the administrative record must include a fact sheet and all documents cited in the fact sheet. 40 C.F.R. § 124.9(b)(3-4). Accordingly, for each controversial source a permitting agency must prepare a fact sheet that describes the major factual, policy and legal issues associated with the proposed PSD permit and include that fact sheet in the record prior to issuing a draft permit. *Id.* Consequently, when a proposed PSD permitting decision triggers ESA issues, it can readily be handled in the same manner as any other "significant factual, legal, methodological and policy" issue is routinely handled. *Id.*

In short, when the PSD regulations governing the requirements for fact sheets and the contents of administrative records are considered together with the requirements of sections 160(5) and 165(a)(2), it becomes clear that an ESA consultation for a PSD permit must be completed prior to the issuance of a draft permit for public comment and such information discussed in a revised fact sheet. 40 C.F.R. § 124.9(b)(3-4).

IL EPA did prepare a fact sheet prior to issuance of the draft PSD permit. The fact sheet did not set forth, however, "the principal facts" and the "significant factual, legal methodological and policy questions" that should have been considered in preparing the draft permit. § 124.8. The fact sheet does not mention any of the endangered species known to be present near the proposed project or any consultation with the U.S. Fish and Wildlife Service. The fact sheet did not mention that the ESA applied to the CWLP permit or even that there might be some controversy about the application of the ESA in this proceeding.

Consequently, as the comment period closes, the public lacks basic information necessary to submit comprehensive written or oral testimony regarding the protection of the endangered species, the threat posed by CWLP's proposed pollution, alternatives thereto, control technology requirements and other appropriate considerations because basic information about the surrounding land use, the presence of endangered species, and the results of any FWS consultation is absent from the public record. Section 165(a)(2). In the Indeck-Elwood proceeding the "consultation" indicated that nitrogen deposition from existing sources of air pollution were already having an impact on certain species of vegetation. At a minimum, the agency must determine whether the nitrogen pollution from the proposed source will contribute and exacerbate the existing nitrogen loading problems facing the species identified in the Indeck-Elwood proceeding.

Finally, the National Oceanic and Atmospheric Agency within the U.S. Department of Commerce recently listed two species of coral under the endangered species act. Specifically, NOAA listed the Elkhorn and staghorn corals. 71 Fed. Reg. 26852 (May 9, 2006); http://sero.nmfs.noaa.gov/pr/pdf/060504%20Acropora%20Listing%20FAQs.pdf. One of the principle reasons NOAA listed these two coral species is global warming and the associated problems of warmer sea temperatures and an increased incidence of hurricanes. Warmer sea temperatures are causing coral bleaching and increased hurricanes are physically damaging the reefs. The principle culprit associated with global warming is carbon dioxide. If constructed, the proposed project will be the largest new source of carbon dioxide in Illinois in over a decade. EPA must consider the impacts of this proposed project over its 40-50 year lifespan and the impacts this project will have on these listed species of coral.

We request that the agency reissue a draft permit and a revised fact sheet that describes how the ESA applies to the issuance of this permit and the results of a completed consultation process.

3. The Applicant Failed to Consider Low-Sulfur Coal in the SAM BACT Determination.

IL EPA has failed to consider low-sulfur coal as part of its BACT determination for sulfuric acid mist. The sulfuric acid mist BACT analysis claims that only two options exist for controlling sulfuric acid mist emissions, a wet electrostatic precipitator and chemical additives. Ap., Sec. 5.9. The BACT analysis failed to evaluate or even acknowledge that low sulfur coals would reduce SAM emission in proportion to the reduction in coal sulfur content.

The Clean Air Act does not allow a permitting agency to exclude lower-sulfur coal from the BACT analysis on the basis of a purported conflict with the applicant's desire to use coal from a nearby coal mine. The Act defines the pollution controls that must be considered during the BACT analysis: "production processes and available methods, systems, and techniques," including, inter alia, "clean fuels." 42 U.S.C § 7479(3) (West 2006). That definition clearly includes low-sulfur coal. The Act defines the factors a permitting agency may "tak[e] into account" in deciding whether an available control should, or should not, be used to establish a facility's BACT limit: "energy, environmental and economic impacts and other costs." Id. That definition clearly does not include divergence from the Applicant's proposed design.

In keeping with that clear statutory language, the Board's decisions establish that the BACT analysis includes all "production processes . . . methods, systems, and techniques" that do not require a change in the source's fundamental "purpose" – not, as EPA now claims, the applicant's " proposed design." See In re Hibbing Taconite Co., 2 E.A.D. 838, slip op. at 9-10 (E.A.B. 1989), PSD Appeal No. 87-3. The *design* of the facility is precisely what the BACT analysis is intended to question. See In re Knauf Fiber Glass, GMBH, 8 E.A.D. 121, 129 (E.A.B. 1999) ("The essence of the BACT determination process . . . is to look for the most stringent emissions limits achieved in practice at similar facilities and to evaluate the technical feasibility of implementing such limits and/or control technologies for the project under consideration."). The Act places the burden on the applicant to justify any "proposed design" that does not achieve emissions limits reflecting the most stringent available control measures. See In re Pennsauken Country, New Jersey, Recovery Facility, 2 E.A.D. 667, slip op. at 5 (Adm'r 1988), PSD Appeal No. 88-8. Accordingly, this Board's decisions confirm that the substitution of cleaner fuels is firmly within the scope of the statutory BACT analysis. In re Brooklyn Navy Yard Resource Recovery Facility, 3 E.A.D. 867, slip op. at 17-18 (E.AD. 1992), PSD Appeal No. 88-10 (use of clean fuel does not "redefine the source").

IL EPA must remand the draft permit and require the applicant to conduct a top-down BACT determination for SAM that considers the use of low-sulfur coal.

4. The Applicant Must Conduct a BACT Determination for SO2.

As described in the comments filed by Keith Harley on behalf of the Sierra Club the proposed Dallman 4 unit's SO2 emissions must be subject to BACT. Such an analysis must be conducted in a top-down manner, and address, *inter alia*, the following four issues: First, the BACT analysis must consider cost-effective lower sulfur coal as an SO2 control option. See comments above for SAM. Second, other coal-fired boilers have been permitted for and have achieved much lower emission rates than the proposed SO2 limit for Dallman 4. Third, the BACT emission limit must contain a control efficiency to ensure maximum control regardless of coal sulfur content. Fourth, the best available control technology for SO2 control on a pulverized coal boiler is a jet bubbling reactor (JBR), which can achieve upwards of 99% control of SO2 from the boiler, is cost effective, and is technologically feasible. Black and Veatch has been one of the U.S. vendors of this product since at least 2001. According to its 2005 SEC 10K filing Dayton Power and Light is in the process of installing the JBR technology on several of its coal-fired power plants.

As an initial matter, the control efficiency of the entire SO2 control train—including limestone injection to the boiler and the scrubber—must be distinguished from control efficiency of the scrubber alone. It is important to note the distinction between a scrubber that achieves 98% control standing alone, and a pollution control train that includes limestone injection and a scrubber that achieves 98% control total. Many wet scrubbers achieve 98% control through the use of the scrubber alone.

To accurately compare alternative wet scrubbing options a BACT determination must determine the additional control achievable with each scrubber technology, assuming the lowest achievable inlet concentration.

The Chiyoda CT-121 WFGD process, which employs a unique absorber design, called a jet bubbling reactor or "JBR," achieves lower SO2 emission rates than a standard wet scrubber. The JBR combines conventional SO2 absorption, neutralization, sulfite oxidation, and gypsum crystallization in one reaction vessel. Black & Veatch prepared an analysis for Wisconsin Public Service Corporation's Weston Unit 4, comparing type of applicable SO2 controls. See Black & Veatch Corp., Wisconsin Public Service Weston Unit 4, Flue Gas Desulfurization System Analysis (April 1, 2003). Black & Veatch described the JBR system as follows:

> This absorber module is unique in the FGD industry because the surface area required for absorption of SO2 from the flue gas is created by bubbling the flue gas through a pool of slurry rather than by recycling slurry through the flue gas as in the other absorber types... Flue gas is pre-cooled with makeup water and slurry prior to entering the JBR's inlet plenum. The inlet plenum is formed by upper and lower deck plates. The flue gas is directed through multiple, 6-inch diameter, sparger tube openings in the lower deck.
>
> These tubes are submerged a few inches beneath the level of slurry in the integral reaction tank in the base of the JBR. The bubbling action of flue gas as it exits the sparger tubes and rises through the slurry promotes SO2 absorption. The gas then leaves the reaction tank area to the outlet plenum via gas risers that pass through both the lower and upper decks. An external horizontal gas flow mist eliminator removes residual mist carried over from the JBR.

> The JBR has several advantages compared to the other absorber modules described previously. Because SO2 absorption is achieved by bubbling flue gas into the reaction tank, the JBR vessel is relatively compact compared to a conventional spray absorber. Gypsum crystals produced in the JBR have a relatively larger size distribution since there is less attrition due to circulation through slurry recycle spray pumps. Most importantly, the removal efficiency of small particulates (less than 10 μm) is substantially better in the JBR compare to conventional spray absorbers. This directly increases the removal of condensed SO3 from the system as compared to most other competing wet scrubber designs, which remove practically no SO3. As with any of the absorber types, the advantages of the JBR must be evaluated on a site-specific basis by comparing total annualized costs at the same guaranteed performance levels with those of competing system proposals.
>
> Chiyoda has installed over 20 JBR FGD systems around the world treating flue gas from over 10,000 MWe of generating capacity. In the US a 110-MWe JBR FGD system was installed at Georgia Power Company's Plant Yates Unit 1 in 1992 as part of the US DOE CCT program. A JBR has been in operation at the University of Illinois on a 40-MWe facility since 1988. The largest North American installation is at Suncor, Inc. in Alberta, Canada. This unit handles flue gas from process boilers (350 MWe equivalent) and has been in operation since 1996.

Id. at 4-11 to 4-14. Unlike a generic wet FGD, which may be less efficient at low inlet concentrations, the bubbling jet reactor has a different design and is capable of achieving 99% or greater SO2 removal at over a wide range of inlet concentrations, including low inlet concentrations.

The JBR can achieve, and has been guaranteed by the manufacturer for, 99% control. It has consistently achieved over 99% control during long term operation at the Shinko-Kobe power plant in Japan. Commercial Experience of CT-121 FGD Plant for 700 MW Electric Power Plant; *see also*, http://www.bwe.dk/pdf/ref-11%20FGD.pdf. This technology, combined with low-sulfur coal, represents the top-ranked control option for a pulverized coal boiler at Dallman 4.

In addition to the Chiyoda system, magnesium enhanced lime (MEL) wet scrubber technology can achieve 99 percent reduction. These types of wet FGD technologies are applicable to Dallman 4, and achieve much greater control of SO2. See Ex. 21; Lewis Benson, Kevin Smith, and Bob Roden, New Magnesium-Enhanced Lime FGD Process, Combined Power Plant Air Pollutant Control Mega Symposium, May 19-22, 2003; Phil Rader, Jon Augeli, and Stefan Ahman, FGD Technologies Achieving SO2 Compliance at the Lowest Lifecycle Cost, CEPSI 2000, Power-Gen Latin America, November 11-13, 2003.

MEL scrubbers use a special type of lime that contains magnesium in addition to its calcitic component. Magnesium salts are more soluble than calcium salts, which makes the scrubbing liquid more alkaline. This results in a higher SO_2 removal efficiency for a significantly smaller absorber tower than for lime alone. This process has a number of benefits including lower liquid recirculation, smaller pumps, lower scrubber-gas-side pressure drop, lower energy requirements, higher availability, and lighter byproduct gypsum than the conventional lime WFGD process. Srivastava and Jozewicz 2001. MEL scrubbers are in use on 15,700 MW of generation and have achieved 99% SO_2 control on high sulfur coals at a liquid-to-gas ratio substantially lower than the conventional limestone process. The MEL vendor, Carmeuse, will guarantee 99% SO_2 removal on high sulfur coal, and Babcock Power and other contractors will wrap the guarantee. MEL has been used on the 300-MW Mitchell Unit 3, Pennsylvania, under a Consent Decree to resolve two civil complaints to compel the owner to comply with SIP-approved rules.[1] The MEL system started up in 1982 and has consistently demonstrated greater than 99% SO_2 control.

BACT is a limit based on the maximum degree of control achievable with the best control technology. The SO2 BACT limit for Dallman 4 must be based on the maximum control achievable from a JBR or a MEL scrubber. The permit must be revised to include a limit based on 99% control of SO_2 at the outlet of the boiler.

In limited circumstances a top-ranked control option is not used to set a BACT limit if energy, environmental, or economic issues justify rejecting the top-ranked control for a less effective option. NSR Manual at B.26-B.29. JBR or MEL scrubbing cannot be rejected as BACT for Dallman 4. EPA has repeatedly interpreted the "collateral impacts clause" as only allowing the rejection of the top control option when impacts unique to the specific facility being permitted make the top control inappropriate at that specific site. "The CAA contemplates the use of a less effective control technology *only when source-specific energy, environmental or economic impacts* or other costs constrain a source from using a more effective technology." General Motors at 381 (emphasis added); see also In re World Color Press, Inc., 3 EAD 474, 479-81 (Adm'r 1990) (remanding PSD decision on basis that alleged negligible collateral impacts did not justify the rejection of more stringent technologies as BACT).

> The determination that a control alternative to be [sic] inappropriate involves a demonstration that circumstances

[1] United States of America v. West Penn Power Company, Civil Action No. 77-1142 and Commonwealth of Pennsylvania, Department of Environmental Resources v. West Penn Power Company, No. 1309, C.D. 1979.

exist at the source which distinguish it from other sources where the control alternative may have been required previously.... In the absence of unusual circumstances, the presumption is that sources within the same source category are similar in nature, and that [they can bear the same] cost and other impacts.

NSR Manual at B.29; In re Kawaihae Cogeneration Project, 7 E.A.D. 107, 116-17 (EAB 1997) (emphasis original); Masonite Corp., 5 E.A.D. at 564; In re World Color Press, Inc., 3 E.A.D. 474, 478 (Adm'r 1990) (collateral impacts clause focuses on the specific local impacts). Impacts that are common to a control device, or are generally experienced at other facilities using a wet scrubber, are not unique to the facility and cannot justify rejecting a top-ranked control option. NSR Manual p. B.47. There are no site-specific, unique collateral impacts associated with JBR or MEL scrubbing for Dallman 4.

CWLP has the burden to demonstrate that it cannot use bubbling jet reactor or MEL control options due to unique collateral impacts. This requires documented evidence. NSR Manual at B.26-B.29; Knauf, 8 E.A.D. at 131 ("A permitting authority's decision to eliminate potential control options as a matter of technical infeasibility, or due to collateral impacts, must be adequately explained and justified.").

5. The Draft Permit Fails To Include a Visible Emission BACT limit for PM and SAM

The draft permit fails to contain a visible emission BACT limit for PM and SAM. Instead, the permit's only visible emission limit is a limit based upon the New Source Performance Standard. This is insufficient to satisfy the requirements of BACT. Any new or modified major source must have a permit requiring BACT. BACT is expressly defined as an "emissions limitation including a visible emission standard," for each criteria pollutant. 40 C.F.R. § 52.21(b)(12). However, the draft permit fails to include limits that include visible emission standards for PM and SAM (which are two of the pollutants that create visible emissions) based on the maximum degree of reduction achievable. Id. Although BACT limits are typically expressed as emission rates (i.e., pounds per hour or pounds per million Btu heat input), the plain language of the Clean Air Act defines BACT as expressly "including a visible emission standard." See 42 U.S.C. § 7479(3). Other coal plants have BACT limits that include visible emission limits. For example, the Springerville facility in Arizona has a BACT limit of 15 percent opacity, and the Mid-America facility in Council Bluffs has an opacity limit of 5 percent. *See* Iowa DNR Permit No. 03-A-425-P, §10a (Permit available online at http://aq48.dnraq.state.ia.us:8080/psd/7801026/PSD_PN_02-258/03-A-425-P-Final.pdf, last visited May 22, 2006). The Fort James (Fort Howard) paper mill in Green Bay, Wisconsin, has a 10% opacity limit, based on BACT for its 500 MW CFB boiler. See Preconstruction Review and Preliminary Determination on the Proposed Construction of a Circulating Fluidized Bed Combustion Boiler for Fort Howard Paper Company to Be Located At 1919 South Broadway, Green Bay, Brown County, Wisconsin, p. 8 (May 26, 1988). The draft permit must be revised to include a visible emission limit for PM and

SAM of no more than 5% opacity, and should include a requirement that CWLP undertake an optimization study to determine the final opacity limit.

6. IL EPA Must Consider IGCC In the BACT Determination

The applicant must consider Integrated Gasification Combined Cycle ("IGCC") technology as part of the BACT determination for the emissions of sulfur dioxide, nitrogen oxide, particulate matter, and sulfuric acid mist. IGCC is an inherently cleaner production process for the generation of electricity from coal that prevents the emissions of regulated pollutants into the atmosphere by removing contaminants such as sulfur and mercury from the hydrocarbons in the coal before the hydrocarbons are burned. IGCC is an established technology that is already "available" for commercial power production applications and at competitive costs, and within the meaning of 42 U.S.C. §7479(3). See e.g., Gregory B. Foote, Considering Alternatives: The Case For Limiting CO2 Emissions From New Power Plants Through New Source Review, 34 ELR 10642, 10647 & n.54, 10659-60; see also Edward Lowe, General Manager, Gasification, GE Energy, GE's Gasification Developments, presented at Gasification Technologies 2005 Conference, San Francisco, CA, (October 10, 2005); Ron Herbanek, Mechanical Engineering Director, E-Gas and Thomas A. Lynch, Project Development Manager, ConocoPhillips, E-Gas Applications for sub-Bituminous Coal, presented at Gasification Technologies 2005 Conference, San Francisco, CA, (October, 11 2005).

There are over 131 gasification projects operating worldwide, which include over 23,750 MW of energy production. Simbec, SFA Pacific, Inc. Gasification Technology Update, presented to the European Gasification Conference, April 8-19, 2002. Many of these units produce chemicals as well as power. Two full-scale commercial IGCC electric generating units are in operation in the United States: Cinergys 192 MW unit at Wabash River, Indiana, and Tampa Electric Co.'s 262 MW unit at Polk plant. See Resource Systems Group, In, EPIndex, available at www.epindex.com. IGCC units constructed with multiple gasifiers can achieve the same reliability levels as conventional baseload facilities. The Eastman Chemical plant in Kingsport, Tennessee utilizes dual gasifiers and experiences availability above 98 percent. Smith, Eastman Chemical Plant Kingsport Chemicals from Coal Operations, 1983-2000, 2000 Gasification Technologies Conference. ChevronTexaco, for example, provides an IGCC plant which achieves greater than 90% availability through the use of multiple gas trains. O'Keefe and Sturm, Clean Coal Technology Options- A Comparison of IGCC vs. Pulverized Coal Boilers, presented to the 2002 Gasification Technologies Conference, October 2002.

IGCC constitutes a fuel cleaning and an innovative fuel combustion technique under the definition of BACT. NOx emissions from an IGCC plant are lower than those for modern coal-fired plants. Additionally, because sulfur is removed from the syngas before combustion, SO2 emissions are less than half of that for a comparable traditionally-fired coal unit. Mercury and CO2 control is also much easier for an IGCC plant than PC or CFB plants. See The Cost of Mercury Removal in an IGCC Plant at 1-2, US DOE, NETL, Sept. 2002. The Wisconsin Department of Natural Resources issued a permit for an IGCC unit in 2004, which included limits significantly lower than those for other coal-fired generation processes. Id. Moreover, EPA recognizes IGCC as an 'inherently lowpolluting process/practice' for generating electricity, as indicated in a presentation given by EPA representatives. See, e.g., Robert J. Wayland, U.S. EPA Office of Air and Radiation, OAQPS, "U.S. EPA's Clean Air Gasification Activities", Presentation to the Gasification Technologies Council Winter Meeting, January 26, 2006; "U.S. EPA's Clean Air Gasification Initiative," Presentation at the Platts IGCC Symposium, June 2, 2005. EPA also found, after significant investigation, that IGCC is an effective method for controlling SO2 emissions from the production of steam generated electricity.

> This can be accomplished by burning... a fuel that has been pre-treated to remove sulfur from the fuel... There are two ways to pre-treat coal before combustion to lower sulfur emissions: Physical coal cleaning and gasification... Coal gasification breaks coal apart into its chemical constituents (typically a mixture of carbon monoxide, hydrogen, and other gaseous compounds) prior to combustion. The product gas is then cleaned of contaminants prior to combustion. Gasification reduces SO2 emissions by over 99 percent.

U.S. EPA, Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978, 70 Fed. Reg. 9706, 9710-11 (February 28, 2005). Therefore, IGCC must be considered in a BACT determination. It is a "clean fuel" option because it "will inherently have only trace SO2 emissions because over 99 percent of the sulfur associated with the coal is removed by the coal gasification process." Id. at 9715; In re Inter-Power of New York, 5 E.A.D. 130, 134 (EAB, 1994) ("[i]n deciding what constitutes BACT, the Agency must consider both the cleanliness of the fuel and the use of add-on pollution controls."). IGCC is also a "innovative fuel combustion technique," within the definition of BACT. Congress explicitly recognized IGCC as a 'production process and available method[], system[] and technique,' when enacting the BACT definition in 1977. The congressional history of the BACT definition includes the following discussion:

> Mr. HUDDLESTON. Mr. President, I send to the desk an unprinted amendment.
>
> The PRESIDING OFFICER. The amendment will be stated.
>
> The legislative clerk read as follows:
>
> The Senator from Kentucky (Mr. HUDDLESTON) proposes an unprinted amendment numbered 387: On page 18, line 15, after "ment" insert "or innovative fuel combustion techniques."
>
> Mr. HUDDLESTON. Mr. President, the proposed provisions for application of best available control technology to all new major emission sources, although having the admirable intent of achieving consistently clean air through the required use of best controls, if not properly

> interpreted may deter the use of some of the most effective controls.
>
> The definition in the committee bill of best available control technology indicates a consideration for various control strategies by including the phrase "through application of production process and available methods, systems, and techniques, including fuel cleaning or treatment." And I believe it is likely that the concept of <u>BACT is intended to include such technologies as low Btu gasification and fluidized bed combustion. But, this intention is not explicitly spelled out, and I am concerned that without clarification, the possibility of misinterpretation would remain.</u>
>
> It is the purpose of this amendment to leave no doubt that in determining best available control technology, all actions taken by the fuel user are to be taken into account- be they the purchasing or production of fuels which may have been cleaned or up-graded through chemical treatment, <u>gasification</u>, or liquefication; <u>use of combustion systems such as fluidized bed combustion</u> which specifically reduce emissions and/or the post-combustion treatment of emissions with cleanup equipment like stack scrubbers.
>
> The purpose, as I say, is just to be more explicit, to make sure there is no chance of misinterpretation.
>
> Mr. President, I believe again that this amendment has been checked by the managers of the bill and that they are inclined to support it.
>
> Mr. MUSKIE. Mr. President, I have also discussed this amendment with the distinguished Senator from Kentucky. I think it has been worked out in a form I can accept. I am happy to do so. I am willing to yield back the remainder of my time.

123 Cong. Rec. S9434-35 (June 10, 1977) (debate on P.L. 95-95) (emphasis added). In fact, IL EPA has concluded IGCC must be considered in the BACT analysis for a coal plant. <u>See</u> Letter from Renee Cipriano, Director, Illinois Environmental Protection Agency ("IEPA") to Thomas Skinner, Regional Administrator, Region V, EPA (March 19, 2003) (announcing IEPA's conclusion that "it is appropriate for applicants for [coal-fired power] plants to consider IGCC as part of their BACT demonstrations."); <u>see also</u> Letter from IEPA to Indeck-Elwood LLC (March 8, 2003)(formally notifying the applicant of the need to supplement its proposal to address IGCC as part of the BACT demonstration).

Contrary to prevalent misconceptions, considering cleaner production processes- which is what IGCC is- does not "define" or "redefine" the source. Indeed, a PC plant and an IGCC plant are the same source: both are processes for creating electricity from coal-fired steam generation. In 1998 EPA adopted a nitrogen oxide limit as part of its new source performance standards that applied to all new electric generating units, regardless of whether it uses pulverized coal or IGCC combustion technologies. Revision of Standards of Performance for Nitrogen Oxide Emissions From New Fossil-Fuel Fired Steam Generating Units, 63 Fed. Reg. 49442 (September 16, 1998). On February 28, 2005 EPA proposed to revise its new source performance standards for the new electric generating units source category and, again, did not distinguish between pulverized coal and IGCC technologies. 70 Fed. Reg. 9706 (Feb. 28, 2005). In other words, EPA treats all electric generating units that burn coal (including gasified coal) as the same source category, and therefore as the same "source."

7. The Source Has Not Analyzed Impacts To Nearby Nonattainment Areas.

The proposed Dallman 4 unit is located close to the Greater Chicago and Greater St. Louis 8-hour ozone and PM2.5 nonattainment areas. We were unable to locate any analysis in the record regarding impacts of the proposed facility on these areas. Additionally, to the extent that the emissions from Dallman 4 will contribute to violations of a NAAQS or increment, these exceedances cannot be excused based on the assertion that the impact from Dallman's emissions is not "significant." The Clean Air Act does not provide an exception for sources that cause or contribute to nonattainment in less than a "significant" amount. Instead, the Act provides a bright line rule that applies to all sources that cause or contribute to a violation of NAAQS or increment—including those whose contribution is not "significant":

> No major emitting facility on which construction is commenced after August 7, 1977, may be constructed in any area to which this part applies unless... the owner or operator of such facility demonstrates... that emissions from the construction or operation of such facility will not cause, or contribute to, air pollution in excess of any (A) maximum allowable increase or maximum allowable concentration for any pollutant in any area to which this part applies more than one time per year, (B) national ambient air quality standard in any air quality control region...

42 U.S.C. § 7475(a)(3). Because the Act does not allow a permit for any source that will cause or contribute to a violation of increment or NAAQS, in any amount, the permit must be denied if Dallman 4 cannot affirmatively demonstrate that it will not cause or contribute to such nonattainment conditions.

8. The Applicant Failed to Consider Alternatives to Building A New Coal-Fired Power Plant.

Section 165(a)(2) establishes the obligation of a permitting agency to consider, and an opportunity for the public to comment on, alternatives to major new sources of air pollution. For attainment areas, section 165(a)(2) prohibits construction of a new major emitting facility unless "a public hearing has been held with opportunity for interested persons * * * to appear and submit written or oral presentations on the air quality impact of such source, alternatives thereto, control technology requirements, and other appropriate considerations." 42 U.S.C. § 7475(a) (emphasis added).

EPA has taken the position repeatedly that energy efficiency, other alternatives, and the need of a project are all factors that can and must be considered by a PSD permitting authority if raised during the public comment process. In 1996 USEPA filed a brief in Ecoelectrica, 7 E.A.D. 56 (EAB 1997), in which it stated:

> Energy conservation is central to meaningful air pollution prevention initiatives, and energy conservation considerations are cognizable under the PSD program. Further the EAB has recognized the legal authority under the PSD program to consider alternatives to a proposed source in Hawaiian Commercial & Sugar Company, 4 EAD at 99-100, and Old Dominion Electric Cooperative, 3 EAD at 793-794. These precedents logically encompass the legal discretion to consider energy conservation as an alternative to a proposed source.

Response of EPA Region II and EPA Office of Air and Radiation to Mr. Arana's Petition for Review, Ecoelectrica LNG Import Terminal and Cogeneration Project, (Dec. 24, 1996). Although the Board did not require consideration of need in that case, the Board did not foreclose review when the state refuses to do so.

> [T]he Board did not mean to address the issue of whether, and under what circumstances, the Board could consider a challenge based on alternate means of meeting energy needs. Rather, as in Kentucky Utilities and as in this case, the Board merely meant to suggest that review under 40 C.F.R. § 124.19(a) was not warranted because the need for the power from a proposed facility would 'more appropriately' be addressed by the responsible State authority.

Ecoelectrica 7 E.A.D. at 74 n.25.

EPA's amicus brief in the subsequent RockGen Energy Center proceeding again states its legal position that a state must actually consider alternatives to avoid review:

> We believe that the EAB should apply the same reasoning here that it did in EcoElectrica regarding consideration of alternatives to a proposed major new source: some entity within state government must have the authority to consider alternatives, including [demand side management] alternatives, to a proposed source when the issue is raised in public comments.

....

> We believe that as the PSD permitting authority, the WDNR does have the authority to effectively limit, on air quality-related grounds, the size and type of plant that may receive a PSD permit. This authority should be used, as necessary, to conduct an appropriate analysis.

Amicus Brief of EPA Region V and EPA Office of Air and Radiation In Response to RURAL's Amended Petition For Review and the Responses of WDNR and RockGen. Although the Board did not reach the merits of this issue in RockGen because the issue "was not raised with sufficient specificity during the comment period and thus not preserved for review by the Board," (In re RockGen Energy Center, 8 E.A.D. 536, 548 (EAB 1999)).

Gregory Foote wrote in his thoughtful article Considering Alternatives: The Case for Limiting CO2 Emissions From New Power Plants Through New Source Review that coal-fired power plants warrant special scrutiny in the PSD permitting process:

> Because the function of any single plant typically is to add to a common pool of electricity supply, the threshold question of need should never be ignored in deciding whether to issue a permit. ... Coal-fired plants in particular merit extra scrutiny because of their tremendous size, longevity, capital and operating costs, demands on fuel suppliers and transmission lines, and adverse environmental impacts. All these public policy concerns are best addressed by reading the CAA as providing no vested right to build a coal-fired plant in any form, and as requiring that every decision to do so only be made after careful consideration of each important aspect of the consequences of that decision. As discussed below, this reading is also the best one under the law.
>
> ...
>
> The threshold question in considering any prospective new or modified electricity generating plan fired by fossil fuels is why the plant should be constructed at all: obviously, it is preferable from the air quality standpoint to rely on renewable energy and more efficient use of existing resources than construct any new fossil-fuel plant.

34 ELR 10642, 10657-58 (July 2004).

In sum, the Clean Air Act affords IL EPA significant authority to protect Illinois' air resources and it is not required to blindly issue permits for sources of air pollution that will have significant public health, economic, and environmental impacts for decades into the future. There are clean renewable energy sources available in Illinois, including wind and energy efficiency measures that could displace most, if not all, of the need for a new coal-fired power plant.

Wind Power

There is a proposed 400 MW wind farm just north of Bloomington, Illinois. This Horizon Wind Project would be the largest new wind farm in North America.[2] We understand this wind farm is looking for customers in Illinois. We urge the IL EPA to consider this alternative as an alternative to building a new coal plant. This is particularly appropriate because the state of Illinois (including the IL EPA headquarters building) consumes approximately ten percent of the electricity generated by CWLP. In his 2005 state of the state speech, Governor Blagojevich called for more of the state's electricity to come from wind turbines and other renewable energy sources. This initiative unveiled in his speech on February 2, 2005 would require at least 8 percent of the electricity sold in Illinois to come from renewable sources by 2012. At present CWLP has no wind power in its portfolio. The IL EPA could demonstrate leadership on clean energy development in accordance with the Governor's commitment by denying CWLP's request to build a new coal-fired power plant and working with the City to instead invest in clean, renewable energy.

Energy Efficiency

There is ample evidence that there is a tremendous opportunity for energy efficiency throughout Illinois, including in Springfield. In March 2006 the Midwest Energy Efficiency Alliance released a report "Midwest Residential Market Assessment and DSM Potential Study," included as attachment 3. In this report, MEEA identifies many common energy efficiency measures and compares the use of such measures in Illinois and neighboring states. There are numerous findings demonstrating that there is a tremendous opportunity to implement additional cost-effective energy efficiency measures in Illinois. Among these findings are the following:

- Only 36 percent of Illinois homes have storm windows, compared to 54 percent in Wisconsin and 54 percent in Missouri. *Id.* at 37
- Only 23 percent of Illinois homes had at least one compact fluorescent light bulb installed, compared to 43 percent in Kentucky and 39 percent in Missouri. *Id.* at 38
- Less than one-half of Illinois households had programmable thermostats. *Id.* at 40.
- Less than 1 percent of Illinois households had installed heat pumps. *Id.*
- Only 29 percent of Illinois households has low-flow showerheads, compared to 51 percent in Wisconsin, 66 percent in Iowa, 66 percent in Kentucky, 68 percent in Michigan, 61 percent in Missouri and 60 percent in Ohio. *Id.* at 43.
- Only Minnesota residents have a lower awareness of the Energy Star program, with less than 6 percent of Illinois residents indicating being "very familiar" with the program. *Id.* at 49.

[2] See http://www.horizonwind.com/projects/whatweredoing/twingroves/.

- The technical potential for energy efficiency in Illinois is over 20 percent of the baseline usage and about 8 percent for "achievable potential." *Id.* at 70.

In summary, this report states:

> The most cost-effective and largest impact electric DSM measures are insulating attics, installing ENERGY STAR heat pumps, installing CFLs [compact fluorescent lightbulbs], removing or replacing secondary or inefficient refrigerators or freezers, and low flow showerheads. In total, these measures comprise over 75% of the achievable DSM potential for measures with costs of conserved energy of 6c/kWh or less. In fact, most of the measures have costs of conserved energy of 3c/kWh or less.

Id. at 73. We urge IL EPA to consider the recommendations in this energy efficiency study as an alternative to authorizing construction of a large new source of air pollution. In addition, because the state consumes a large portion of CWLP's electrical output, we urge IL EPA to work with its sister agencies to implement cost-effective energy efficiency measures instead of approving a large new coal plant.

No Demonstrated Need for the Project

The applicant has not demonstrated that there is any need for a 250MW coal-fired power plant and its attendant pollution. CWLP has not demonstrated it needs this amount for city residents. In fact, CWLP predicts it will sell a significant portion of its proposed output from the new facility (in combination with Dallman 1-3) onto the open market. In the absence of a need to meet the needs of the residents of Springfield, the IL EPA should seriously consider the alternatives described above, namely wind power and energy efficiency.

9. The Springfield Airport Meteorological Data are Unacceptable for Air Dispersion Modeling

The PSD Application assesses compliance with the NAAQS and PSD increments using five years of meteorological data from Springfield Capital Airport. The airport data, collected at a location 8 miles from CWLP, is neither site-specific nor is the quality of the data acceptable for air dispersion modeling. The CWLP PSD Application, which relies on these data for air modeling, is therefore flawed.

For air dispersion modeling purposes, airport data are among the least desirable. Problems with location and the general quality of data are the primary concerns. EPA, in their <u>Meteorological Monitoring Guidance for Regulatory Modeling Applications</u>, summarizes these concerns about using airport data:

> For practical purposes, because airport data were readily available, most regulatory modeling was initially performed using these data; however,

one should be aware that airport data, in general do not meet this guidance.[3]

First, the Springfield airport data are not site-specific to the CWLP facility. The different land uses at CWLP and the airport, respectively, create site-specific meteorological conditions such that one location is not representative of the other. Springfield Capital Airport is comprised or concrete runways, parking lots, passenger terminals, and other structures associated with air travel activities. These surface and building characteristics in turn affect the boundary layer meteorology present at the airport.[4] In addition, landings, takeoffs, and idling of airplanes affect the site-specific conditions at the airport such that the meteorological conditions are not representative of the area surrounding the CWLP facility.

The major issue, however, is the quality of the meteorological data collected at Springfield Capital Airport. It is important to remember that the airport data are not collected with the thought of air dispersion modeling in mind. For example, airport conditions are typically reported once per hour, based on a single observation (usually) taken in the last ten minutes of each hour. EPA recommends that sampling rates of 60 to 360 per hour, at a minimum, be used to calculate hourly-averaged meteorological data.[5] Air dispersion modeling requires hourly-averaged data, which represents the entire hour being modeled, and not only a snapshot taken in one moment during the hour.

In addition, data collected at Springfield Capital Airport are not subject to the system accuracies required for meteorological data collected for air dispersion modeling. EPA recommends that meteorological monitoring for dispersion modeling use equipment that are sensitive enough to measure all conditions necessary for verifying compliance with the NAAQS and PSD increments. For example, low wind speeds (down to 1.0 meter per second) are usually associated with peak air quality impacts – this is because modeled impacts are *inversely* proportional to wind speed. Following EPA guidance, wind speed measuring devices (anemometers) should have a starting threshold of 0.5 meter per second or less.[6] And the wind speed measurements should be accurate to within plus or minus 0.2 meter per second, with a measurement resolution of 0.1 meter per second.[7]

The Springfield Airport data used by CWLP, rather than being measured in 0.1 meter per second increments, is based on wind speed observations that are reported in whole knots. This is evidenced by examining the meteorological data files used in the PSD Application modeling analysis. Every modeled hourly wind speed is a factor of 0.51 or 0.52 meter per second (the units required for input to the air dispersion model), which exists because one knot equals 0.51479 meter per second. The once-per-hour observations at

---

[3] EPA, Meteorological Monitoring Guidance for Regulatory Modeling Applications, EPA-454/R-99-05, February 2000, p. 1-1.
[4] Oke T.R., <u>Boundary Layer Climates</u>, Halsted Press, 1978, pp. 240-241.
[5] EPA, Meteorological Monitoring Guidance for Regulatory Modeling Applications, EPA-454/R-99-05, February 2000, p. 4-2.
[6] Id., p. 5-2.
[7] Id., p. 5-1.

Springfield Capital Airport (in whole knots, no fractions or decimals) were converted to meters per second and can therefore be back-converted to the whole knot measurements originally reported by the airport.

To further exemplify the problem of using the airport data, the lowest wind speed included in the meteorological data files used in the PSD Application (with two exceptions) is 1.54 meters per second (three knots). Out of a possible 43,828 hours in the five-year modeling data set, there are a total of two hours with reported wind speeds equal to 1.03 meters per second (two knots).[8] Otherwise, all winds lower than three knots are reported as calms, and are thus excluded from the modeling analyses. There are 1,680 such calm hours in the meteorological data files used in the PSD Application. In no uncertain terms, the conditions most crucial for verifying compliance with the NAAQS and PSD increments (low wind speeds) are being excluded from the CWLP analysis because of the choice to use the airport data.

Sensitive and accurate measurements of wind speeds are necessary for measuring winds down to 0.5 meter per second (about one knot), which can then be used as 1.0 meter per second in the air dispersion modeling analyses. There would be no need to label such low wind speed hours as calm, which will greatly increase the number of hours included in the modeling analyses. Again, it is these low wind speed hours which must be included in the modeling data set to verify compliance with the NAAQS or PSD increments. The meteorological data used in the PSD Application includes only two hours out of five years with a wind speed below 1.54 meters per second, and to compound the problem, lists all other wind speeds less than three knots as calms, which are then excluded from the model calculations.

We examined the effect of calm hours on the highest second high (HSH) 24-hour PM10 modeled concentrations analyzed in the PSD increment consumption analysis. As part of their PSD application, CWLP performed modeling that showed a HSH 24-hour PM10 concentration of 26.96 $\mu g/m^3$ – a value about 90% of the allowable increment of 30 $\mu g/m^3$. This is the result obtained with the ISCST3 calm processing approach which excludes calm hours from the modeling calculations.

The simplest method for examining the effect of calm hours on the HSH 24-hour PM10 concentrations is to use the ISCST3 non-default option, NOCALM. In essence, NOCALM includes all calm hours in the modeling calculations by setting the "calm" wind speed of 0.0 m/s to 1.0 m/s. This can be verified by using the default calm processing option, and manually changing all hours with 0.0 m/s winds to 1.0 m/s in the meteorological data sets from Springfield Capital Airport – the results are the same. Using the NOCALM option increases the HSH 24-hour PM10 concentration from 26.96 $\mu g/m^3$ to 47.73 $\mu g/m^3$, which significantly exceeds the allowable increment of 30 $\mu g/m^3$.

---

[8] The reported hours with wind speeds equal to 2 knots occurred on 6/6/1988, hour 2, and 6/21/1991, hour 8. It is impossible to determine why these two hours were included in the data set, while all other hours with wind speeds less than 3 knots were listed as calm.

Applying NOCALM processing, however, comes with some valid criticism. In certain circumstances, several or more consecutive calm hours may occur in the meteorological Springfield Airport data set. Calm hours are identified with wind speeds of 0.0 m/s, and for these hours the flow vector (direction towards which the wind is blowing) is set equal to the last non-calm hour value and then randomized within a 10 degree sector. Thus, a relatively narrow band of flow vectors could occur within consecutive calm hours. This leads to relatively higher modeled concentrations due to winds repeatedly impacting the same receptors.

While the application of NOCALM processing may appear to be overly conservative, it is more appropriate for verifying PSD increment concentrations than simply excluding the calm hours as was done in the CWLP PSD application. This is because using Springfield Capital Airport data and then excluding the calm hours does not verify compliance with the applicable standards and increments – the most critical condition necessary for confirming compliance are eliminated from the data set.

To further examine the effect of including calm hours on modeled concentrations, we analyzed the effect of setting calm hour winds to 1.0 m/s, and then randomizing the associated hourly flow vectors within wider sectors than the 10 degrees included in the Springfield Capital Airport data set. This has the advantage of including the calm hours in the modeling database, while not assessing impacts within a narrow band of flow vectors should consecutive calm hours exist.

This analysis was performed using the Springfield Capital Airport meteorological data, and a processing program that changes calm hour winds to 1.0 m/s while randomizing the associated flow vector within a specified sector width. The FORTRAN code to the program we created is attached in Appendix A. While it is virtually impossible to tell whether all calm hours should be modeled with 1.0 m/s winds (some hours will actually be calm), the actual number of true calms should be very small. Typically, when properly measured with modern anemometers, there are only a few calm hours in a meteorological data base per year.[9]

The results of our calm hour modeling analysis are shown in the table below. By including calm hours in the modeling data set, and randomizing the coupled flow vectors within a 30 degree sector, the HSH 24-hour PM10 modeled concentration is 44.29 $\mu g/m^3$. Increasing the sector width of random flow vectors to 60 degrees results in a HSH 24-hour PM10 modeled concentration of 36.34 $\mu g/m^3$; randomizing flow vectors within a very-wide 90 degree sector width still results in a HSH 24-hour PM10 modeled concentration of 35.50 $\mu g/m^3$. All of these examples exceed the PSD allowable increment of 30 $\mu g/m^3$. This analysis shows that CWLP emissions and assumptions as presented in their application, modeled with the wind conditions necessary for verifying compliance, will exceed allowable increments.

---

[9] For example, the pre-construction monitoring data set for the Newmont Nevada proposed coal-fired power plant has five calm hours (10 meter winds) in the one-year period from 9/1/2003 through 8/31/2004.

Year Met Modeled	CWLP Modeled	ISCST3 NOCALM Option	Min WS=1.0 m/s, Random FV within 30 degree sector	Min WS=1.0 m/s, Random FV within 60 degree sector	Min WS=1.0 m/s, Random FV within 90 degree sector
1987	26.96	34.32	33.10	33.43	29.42
1988	23.56	40.50	38.95	36.26	29.02
1989	26.22	47.73	44.29	36.34	35.50
1990	20.96	36.34	30.88	26.50	24.72
1991	24.72	38.58	41.88	32.69	27.74
Max:	26.96	47.73	44.29	36.34	35.50

The extent of the sector width within which the flow vectors should be randomized is debatable; however, the conclusion that excluding calm winds from the data base is inappropriate is not. The table above clearly shows that recapturing the calm hours will significantly increase modeled concentrations. This is very important for verifying compliance with applicable standards and increments, particularly when the applicant-modeled concentrations are already close to the threshold values.

Using airport data for modeling huge emitters of air pollutants, such as CWLP, must not be allowed. Excluding the calm hours from modeled concentrations reduces the predicted impacts – a benefit to CWLP and a detriment to the surrounding air quality. This is very convenient for the applicant, and helps to explain why complicated major sources of air pollutants still rely on antiquated airport meteorological data.

If CWLP insists on using Springfield Capital Airport data, which do not meet EPA requirements in the Meteorological Monitoring Guidance for Regulatory Modeling Applications, then they should be required to use ISCST3 with the non-default NOCALM option. Preferably, however, CWLP should have collected at least one-year of pre-construction meteorological data consistent with EPA Meteorological Monitoring Guidance for Regulatory Modeling Applications. In any event, the current CWLP modeling is unacceptable for NAAQS and increment consumption analyses.

10. Preconstruction Monitoring Should Have Been Required

IEPA should have required CWLP to collect pre-construction meteorological data for use in their PSD Application modeling. CWLP, which is a major emission source of many air pollutants, should not be assessed for PSD increment compliance using non site-specific meteorological data collected with none of the quality assurances necessary for air modeling data.[10]

Pre-construction meteorological data for projects that trigger PSD review is already being required for coal-fired power plants. Two recent projects in Nevada, Granite Fox Power (near Gerlach) and Newmont Nevada (Boulder Valley), have collected at least one year of pre-construction meteorological data. The data requirements, specific for input to air dispersion modeling for NAAQS and PSD increment analyses, are specified by the State

[10] USEPA, Ambient Monitoring Guidelines for Prevention of Significant Deterioration (PSD), EPA-450/4-87-07, May 1987, p. 55.

of Nevada.[11] The State of Nevada Guidelines state: "Current on-site meteorological data are required for input to dispersion models used for analyzing the potential impacts from the air pollution sources at the facility."[12]

Even smaller air regulatory agencies have been requiring pre-construction meteorological data for many years. As part of their PSD program, the Santa Barbara County (California) Air Pollution Control district requires at least one-year of pre-construction air quality and meteorological monitoring.[13] The meteorological monitoring requirements are specified in a detailed protocol that implements their PSD Rule.[14] PSD sources in Santa Barbara County must collect site-specific hourly-averaged values for the following meteorological parameters:

- Horizontal wind speed and wind direction (both arithmetic and resultant)
- Horizontal wind direction standard deviation (sigma theta)
- Standard deviation of wind speed normal to resultant wind direction (sigma v)
- Vertical wind speed
- Vertical wind speed standard deviation (sigma w)
- Standard deviation of the vertical wind direction (sigma phi)
- Ambient air temperature
- Shelter temperature[15]

The CWLP air emissions are enormous and are released in a complex arrangement of point, area, and volume sources. Using an antiquated, low-quality, and non site-specific meteorological data set, for no other reason than to expedite the permitting process for the applicant, invalidates the entire air quality impact analysis. The PSD application should be denied because of this poor modeling practice, and not be resumed until CWLP has collected at least one year of site-specific meteorological data consistent with USEPA's Meteorological Monitoring Guidance for Regulatory Modeling Applications.

11. The Modeling Results are Based on Underestimated PM10 Emissions

Dispersion modeling is used to demonstrate compliance with the NAAQS and PSD increments in ambient air. Modeled concentrations are added to a regional background value to determine the total concentration used in comparison to the NAAQS. It is important that the emissions used in this modeling are accurate. It appears that emissions from certain fugitive source, such as haul roads, were underestimated by using unrealistically low silt loading and high control efficiencies. This section discusses the impact of silt content on modeled 24-hour NAAQS and increments. We note that some of the control efficiencies assumed for dust control, up to 96% at the entrance haul roads are unrealistic and unlikely to be achieved in practice with the mitigation measures

[11] Nevada Bureau of Air Pollution Control, Ambient Air Quality Monitoring Guidelines, May 4, 2000.
[12] Id., p. 6.
[13] Santa Barbara County Air Pollution Control District, Rule 803, Prevention of Significant Deterioration.
[14] Barbara County Air Pollution Control District, Air Quality and Meteorological Monitoring Protocol for Santa Barbara County, October 1990.
[15] Id., p. 57.

required in the permit. See further discussion in letter submitted by Keith Harley on behalf of our organizations.

1. Impact of Silt Content on 24-PM10 NAQS and Class II Increments

Trucks will be used to import coal, limestone, and ammonia and to export fly ash, bottom ash, gypsum, and brine solids. Trucks suspend dust on the haul road surface and shoulders of the road, creating fugitive PM10 emissions. These fugitive PM10 emissions contribute significantly to modeled PM10 increments.

Dust emissions from paved roads vary with the amount of silt on the road surface, referred to as "silt loading." The haul road PM10 emissions included in the modeling assume a background silt loading value of 2 g/m^2, characterized as yielding a "worst-case" PM10 emission rate and accepted by IEAP. Ap., p. 3-13. Elsewhere, this silt loading is reported as representing access and low ADT (average daily traffic) roads, referenced to AP-42. Ap., Appx. C, Haul Road Emission Calculation – Rev. 1.

The silt loading value is critical here because fugitive PM10 emissions from the haul roads are the major contributor to the 24-hour PM10 NAAQS and increment. If the silt loading were slightly higher than 2 g/m^2, the project would cause violations of the 24-hour PM10 NAAQS and increment. The permit does not require that silt loading be measured and reported to assure compliance with the NAAQS and increments. See discussion of PM Emissions in Keith Harley's Letter, Haul Road Comment..

The paved roads of interest here are within the boundary of an existing industrial site and are heavily traveled. Thus, they are industrial roadways. Silt loading values of industrial roads are much higher than 2 g/m^2, vary greatly, and are reported elsewhere in the same chapter of AP-42, Section 13.2.1. AP-42 specifically states that the use of a tabulated default value for silt loading results in only an order-of-magnitude estimate of the emission factor for fugitive dust from truck traffic on paved roads, and, therefore, recommends the collection and use of site-specific silt loading data. In the event that a site-specific value is not available (as here), AP-42 recommends the selection of an appropriate mean value from a table listing silt loadings that were experimentally determined for a variety of industrial roads.

The industrial roadway table provides a range of mean silt loading values from 7.4 to 292 g/m^2. AP-42 Sec. 13.2.1-4, Table 13.2.1-4. The modeled haul road PM10 emissions are based on a silt loading value of 2 g/m^2, thereby considerably underestimating PM10 emissions from paved roads within the facility. Modeling was performed to determine the potential impacts from the project in comparison with the NAAQS and PSD increments. Two emissions scenarios were evaluated. The first scenario is based on using the lower end of AP-42 industrial roadway range. The second scenario is based on a 10 percent increase in the silt loading value, still considering less than the AP-42 value.

2. Comparison to NAAQS

If the lower end of the AP-42 industrial roadway range of 7.4 g/m^2 is assumed, the PM10 emission factor for haul roads increases from 0.4430 lb/VMT used by the applicant to 1.036 lb/VMT or by a factor of 2.34. If the haul road emissions in the dispersion modeling are increased by a factor of 2.34, the modeled highest sixth high 24-hour concentration from the facility increases from 86.1 ug/m^3 to 189 ug/m^3. The total impact, including regional background, would increase to 252 ug/m^3, which is 68 percent greater than the NAAQS. The modeled highest sixth high value is predicted at UTM location 276816.19 East, 4403824 North for September 24, 1989 meteorological data.

The modeled maximum annual concentration from the facility increases from 24.0 ug/m^3 to 51.3 ug/m^3. The total impact, including regional background, is 70.6 ug/m^3, which is 41 percent greater than the NAAQS. The highest modeled annual value is predicted at UTM location 277016.19 East, 4403965 North for 1990 meteorological data.

These modeled concentrations clearly cause or contribute to exceedances of the 24-hr PM10 NAAQS and Class II increment. In this case, a PSD permit cannot be issued until the NAAQS and increment violations are entirely corrected and the permit is revised to contain enforceable conditions, e.g., measurement of silt content and other factors relied on in the emission calculations. NSR Manual, p. C.52, C-53.

Modeled violations of the 24-hour NAAQS are predicted if the silt loading factor is increased ten percent, from 2 to 2.2 g/m^2. The modeled highest sixth high 24-hour concentration from the facility increases from 86.1 ug/m^3 to 91.4 ug/m^3. The total impact, including regional background is 154.4 ug/m^3. This small increase is sufficient to make the difference between compliance and non-compliance with the 24-hour NAAQS. The modeled highest sixth high value is predicted at UTM location 276816.19 East, 4403824 North for May 14, 1989 meteorological data.

Maximum Modeled Concentrations in Comparison to the NAAQS

Pollutant	Averaging Period	Silt Loading (g/m^2)	Concentration (ug/m^3)			
			Modeled	Background	Total	NAAQS
PM10	24-hour	2	86.1	63	149.1	150
		2.2	91.4	63	154.4	150
		7.4	189.4	63	252.4	150
	Annual	2	24.0	19.3	43.3	50
		2.2	25.3	19.3	44.3	50
		74	51.3	19.3	70.6	50

3. Increment Consumption

Modeled haul road emissions from increment consuming sources were increased for the 2.2 and 7.4 g/m^2. If the haul road emissions in the dispersion modeling are based on the lower end AP-42 silt loading value, the modeled highest second high 24-hour concentration for any year from the facility increases from 27.0 ug/m^3 to 55.0 ug/m^3. This value is 83 percent greater than the allowable increment. The modeled highest second high value is predicted at UTM location 276807.91 East, 4403797 North for August 12, 1987 meteorological data.

If the modeling emissions are based on a ten percent increase in the silt loading factor, to 2.2 g/m^2, the modeled highest second high 24-hour concentration increases from 27.0 ug/m^3 to 29.6 ug/m^3. This value consumes 98.6 percent of the allowable increment. The modeled highest second high value is predicted at UTM location 276807.91 East, 4403797 North for September 5, 1987 meteorological data.

Maximum Modeled Increment Consumption

Pollutant	Averaging Period	Silt Loading (g/m^2)	Concentration (ug/m^3)	
			Modeled	Allowable Increment
PM10	24-hour	2	27.0	30
		2.2	29.6	30
		7.4	55.0	30
	Annual	2	5.5	17
		2.2	5.7	17
		7.4	10.0	17

Thank you for considering these comments.

Sincerely,

Bruce Nilles
Sierra Club

Cc: Constantine Blathras

Appendix A: Fortran Code to Meteorological Data Processing Program

```
      program metcalm! cms 5/8/06

c     This program reads an ISCST3 ascii met file,
c     and converts ws = 0.0 m/s to ws = 1.0 m/s.
c     It also includes ran1 function from Fortran Numerical
c     Recipes, pp. 270-271, to randomize calm wind FVs within
c     a specified degree sector (see sector.inf).

c     Use mcr.bat to run:
c     mcr <sector.inf 19%1.asc 19%1r%2.asc 19%1r%2.clm;
c     where %1 is the 2-digit year,
c     and %2 is the sector width in degrees.

      integer yr,mo,da,hr,kst,i,negintr,ni
      real*8 fv,ws,t,rmh,umh,fva,fvo,sct
      character*27 line1

      open(1,file='sector.inf')! Sector info. input
      open(2,file=' ')! ISCST3 met input
      open(3,file=' ')! ISCST3 met output
      open(4,file=' ')! diagnostic output

      i=0

      read(2,'(a27)') line1
      write(3,'(a27)') line1

      read(1,*) sct

      do while(.true.)
        i = i+1
        read(2,10,end=99) yr,mo,da,hr,fvo,ws,t,kst,rmh,umh
10      format(4i2,2f9.4,f6.1,i2,2f7.1)
        if(ws.lt.1.) then
          ws = 1.0
          negintr=sign(i,-2)! ran1 needs a negative int seed
          ni=negintr
          fva = ran1(negintr)
          fv = fvo+sct*fva-sct/2.! randomize in sector
          fv = float(ifix(fv+0.501))! fix and then float
          if(fv.gt.360.) fv = fv-360.
          if(fv.le.0.) fv = fv+360.
          write(4,20) yr,mo,da,hr,i,ni,sct,fva,sct*fva,fvo,fv
20        format(4i2,2i6,f5.0,4f9.4)
        else
          fv = fvo
        endif
        write(3,10) yr,mo,da,hr,fv,ws,t,kst,rmh',umh
      enddo

99    close(2)
      close(3)
      close(4)

      stop
```

```
      end

      function ran1(idum)
c     This is Function ran1 from Fortran Numerical Recipes
      integer idum,ia,im,iq,ir,ntab,ndiv
      real ran1,am,eps,rnmx
      parameter (ia=16807,im=2147483647,am=1./im,
     +iq=127773,ir=2836,ntab=32,ndiv=1+(im-1)/ntab,
     +eps=1.2e-7,rnmx=1.-eps)
      integer j,k,iv(ntab),iy
      save iv,iy
      data iv /ntab*0/, iy /0/

      if(idum.le.0.or.iy.eq.0) then
        idum=max(-idum,1)
        do j=ntab+8,1,-1
          k=idum/iq
          idum=ia*(idum-k*iq)-ir*k
          if(idum.lt.0) idum=idum+im
          if(j.le.ntab) iv(j)=idum
        enddo
        iy=iv(1)
      endif

      k=idum/iq
      idum=ia*(idum-k*iq)-ir*k
      if(idum.lt.0) idum=idum+im
      j=1+iy/ndiv
      iy=iv(j)
      iv(j)=idum
      ran1=min(am*iy,rnmx)
      return
      end
```

EXHIBIT 3

Illinois Environmental Protection Agency
1021 North Grand Avenue East
Springfield, Illinois

Project Summary for a Construction Permit Application from City Water Light and Power for Dallman Unit 4 Springfield, Illinois

Site Identification No.: 167120AAO
Application No.: 04110050
Date Received: November 18, 2004

Schedule:

Public Comment Period Begins: February 4, 2006
Public Hearing: March 22, 2006
Public Comment Period Closes: April 21, 2006

Illinois EPA Contacts:
Permit Analyst: Shashi Shah
Community Relations Coordinator: Brad Frost

I. INTRODUCTION

City Water, Light and Power (CWLP), the municipal utility of the City of Springfield, has applied for a permit to construct a new coal-fired electrical generating unit (Dallman Unit 4) at its existing power plant adjacent to Lake Springfield. The new unit would have a nominal electrical capacity of 250 megawatts (gross output). It would replace the two Lakeside Units at the plant, which are the oldest units now at the plant.

The Illinois EPA, Bureau of Air reviews applications for air pollution control permits. The Illinois EPA has reviewed CWLP's application and made a preliminary determination that the project, as set forth by CWLP, in the application meets applicable requirements. Accordingly, the Illinois EPA has prepared a draft of the air pollution control construction permit that it would propose to issue for this project. The permit is intended to identify the applicable rules governing emissions from the proposed project and to set limitations on those emissions. The permit is also intended to establish appropriate compliance procedures for the project, including requirements for emissions testing, continuous monitoring, recordkeeping, and reporting.

II. PROJECT DESCRIPTION

The proposed generating unit would have one coal-fired boiler, which would produce steam that would be used in a new steam turbine-generator to produce electricity. The nominal rated heat input capacity of the boiler would be about 2,440 million Btu/hr. The boiler would be designed to use Illinois coal as its principal fuel, which would continue to be delivered by truck like the coal supply for the existing units at the plant. Natural gas would be the auxiliary fuel for the boiler, used during startup to bring the boiler system up to normal operating temperature prior to firing of coal and during shutdown of the boiler after coal firing has been discontinued.

The boiler would be a pulverized coal boiler. The coal would be pulverized or ground into a fine powder before being blown into the furnace section of the boiler with part of the combustion air through a number of burners. The remainder of the combustion air, the secondary air, would be blown into the boiler through ports or nozzles to complete combustion.

The boiler would be equipped with a multi-stage system to minimize and control emissions. The boiler would be equipped with low NO_x burners and use good combustion practices to minimize emissions of nitrogen oxides (NO_x), carbon monoxide (CO), and volatile organic material (VOM). The add-on control train for the boiler would include a selective catalytic reduction (SCR) system for control of NOx, a fabric filter or baghouse for control of particulate matter (PM), wet flue gas desulfurization (WFGD) or scrubber for control of sulfur dioxide (SO_2), and a wet electrostatic precipitator (WESP) for control of sulfuric acid mist and condensable particulate matter. The exhaust from the boiler would then be vented out through a 450-foot high stack.

Other emission units to be constructed as part of the project would include: storage, processing and handling equipment for coal, limestone, ash and other materials; a cooling tower; various roads and parking areas; and diesel engines for emergency power.

III. EMISSIONS

A. Project Emissions

The potential emissions of the proposed boiler are listed below. Potential emissions are calculated based on continuous operation at the maximum load. Actual emissions will be significantly less to the extent that the boiler would operate at less than its maximum capacity and with a compliance margin for applicable emission limits.

Pollutant	Potential Emissions (Tons Per Year)
Particulate Matter Filterable	160
Particulate Matter 10 (Total PM)	374
Sulfur Dioxide (SO_2)	2,135
Nitrogen Oxides (NO_x)	1,067
Carbon Monoxide (CO)	1,281
Volatile Organic Material (VOM)	38.4
Fluorides	2.6
Sulfuric Acid Mist	53
Mercury	0.023
Hydrogen Chloride	76.5
Lead	0.22

Particulate matter will also be emitted from the ancillary operations that support the operation of the new boiler. These include the facilities for storage and handling of coal, limestone, ash and gypsum, a cooling tower, and roadways. The potential particulate matter emissions of these ancillary operations are about 27.4 tons per year.

B. Net Change In Emissions

The net change in annual emissions from this project is shown below. The emission decreases for the shutdown of the two existing Lakeside units, Units 7 and 8, are based on data for the actual emissions of these units, calculated as the average of emissions in 2002 and 2003. Emissions of SO_2 and NOx were determined by continuous emission monitoring conducted under the federal Acid Rain Program. This monitoring data is collected from sources by the Clean Air Markets Division of USEPA's Air and Radiation Branch and posted on the Internet. Emissions of other pollutants were estimated using operating data and appropriate factors from USEPA's *Compilation of Air Pollutant Emission Factors*, AP-42.

The determination of the net change in emissions from this project also considers increases in emissions from contemporaneous projects that occurred within the last five years. The first such project is three diesel engines installed by CWLP in 2002 pursuant to Construction Permit 01070019. The emission increases from this project was determined as the permitted emissions of these new emission units, as set by the applicable construction permit. The other contemporaneous project is a spray dryer system for treatment of certain wastewater streams from the plant, for which an application for a construction permit is pending, Application 05030023. The emission increases from this proposed project was determined as the permitted emissions of the new emission units, as currently requested by CWLP in the construction permit application.

After considering the contemporaneous decreases in emissions from the permanent shut down of the Lakeside Units and the increases in emissions from other contemporaneous projects, this project is accompanied by a net decrease in emissions of SO_2 and NOx.

Summary of Net Changes in Annual Emissions of PSD Pollutants (Tons)

Pollutant	Project Emissions	Contemporaneous Emissions Increases and Decreases			Net Change in Emissions
		Decrease: Shutdown of Lakeside	Increases		
			New Diesel Engines	Prop. Spray Dryer Sys.	
NO_x	1070	1,262	39.4	14.0	-138
SO_2	2135	7,741	0.8	0.1	-5605
CO	1282	32.1	4.7	21.1	1276
VOM	38	7.03	1.0	11.6	43.6
PM (Filterable)	187	6.36	1.1	13.7	195
PM (Total)	401	6.36	1.1	13.7	409
Sulfuric Acid Mist	53	32.2	-	-	20.8
Fluorides	2.6	*	-	-	2.6
Lead	0.22	*	-	-	0.22

*CWLP did not evaluate the decrease in emissions of this pollutant.

IV. APPLICABLE EMISSION STANDARDS

All emission units in Illinois must comply with Illinois Pollution Control Board emission standards. The Board's emission standards represent the basic requirements for sources in Illinois. The various emission units in the proposed project should readily comply with applicable Board standards.

The proposed boiler is also subject to the federal New Source Performance Standards (NSPS), 40 CFR 60 Subpart Da, for electric utility steam generating units. The NSPS sets emission limits for NOx, SO_2, PM and mercury emissions from the boiler. Requirements for testing, continuous emissions monitoring, record keeping, and reporting are also specified. Coal handling operations and limestone handling operations associated with the new boiler are also subject to other NSPS. The Illinois EPA administers NSPS in Illinois on behalf of the USEPA under a delegation agreement.

V. OTHER APPLICABLE REGULATIONS

A. Prevention of Significant Deterioration (PSD)

Under the federal rules for Prevention of Significant Deterioration of Air Quality (PSD), 40 CFR 52.21, the proposed project is a major project for emissions of PM, CO and sulfuric acid mist.

The PSD program addresses emissions of certain pollutants regulated under the Clean Air Act, i.e., PSD pollutants. PSD pollutants are regulated under the Clean Air Act not including hazardous air pollutants and any pollutants for which local air quality is designated nonattainment, which is not of concern for the proposed project. Since the existing CWLP power plant is already a major source for purposes of the PSD rules, with permitted annual emissions of more than 100 tons for a number of pollutants, the proposed project is major for PSD pollutants for which the project would constitute a major modification. For a project involving new emission units, such as the proposed project, a project is generally considered a major modification for a specific PSD pollutant if the annual emissions of the pollutant from the project would potentially be above the significant emission rate set by the PSD rules for the particular pollutant. However, a permit applicant may elect to show that even though the increase in emissions form a proposed project is significant, the net increase in emissions, considering contemporaneous and creditable increases and decreases in emissions of the pollutant, is not significant.

As summarized below, the proposed project would potentially be accompanied by significant increases in emissions of SO_2, NOx, PM, CO and sulfuric acid mist. However, CWLP has elected to show that the project would not be accompanied by a significant net increase in emissions of SO_2 and NOx, relying on the accompanying decrease in emissions from the shutdown of the two existing Lakeside Units. As a result, the proposed project is not subject to PSD for SO_2 or NOx, even though the emissions increases for these pollutants would be considered significant when looked at by themselves. The proposed project is only a major project for emissions of PM, CO and sulfuric acid mist under the PSD rules, subject to the substantive requirements of the PSD rules these pollutants

Project Emissions for Purposes of PSD Applicability (Emissions in Tons/Year)

Pollutant	Project Emissions	Net Change in Emissions	PSD Significant Emission Rate
NO_x	1070	-138	40
SO_2	2135	-5605	40
CO	1282	-	100
VOM	38	-	40
PM (Filterable)	187	-	25
PM (Total)	401	-	15
Sulfuric Acid Mist	53	-	7
Fluorides	2.6	-	3
Lead	0.22	-	0.6

B. Maximum Achievable Control Technology (MACT)

While a case-by-case determination of Maximum Achievable Control Technology (MACT) is not currently required for emissions of hazardous air pollutants (HAPs) from the proposed boiler, the draft permit contains such a determination in the event that circumstances change so that such a determination is required in the future. In particular, a MACT determination is not currently required for the proposed boiler because USEPA has made an official finding that it is neither appropriate nor necessary to regulate utility steam generating units under Section 112 of the Clean Air Act, which addresses requirements for emissions of HAPs. USEPA made this finding in March 2005 when it adopted the federal "Clean Air Mercury Rule," (CAMR). This rule, which provides for control of mercury emissions from coal-fired utility units on a national basis with a cap-and-trade type program, was adopted under Section 111 of the Clean Air Act, rather than Section 112 of the Clean Air Act.

However, this USEPA finding with respect to the appropriate basis to regulate utility steam generating units has been appealed by the State of Illinois and others. Accordingly, if this appeal is successful and USEPA's finding with respect to utility units is overturned, a case-by-case determination of MACT could be required for the new boiler, pursuant to Section 112(g) of the Clean Air Act. This is because the boiler would be considered a major unit for emissions of (HAPs) under Section 112(g) of the Clean Air Act absent USEPA's finding with respect to utility steam generating units. For example, due to the trace levels of chlorine in the coal supply to the boiler, the boiler would have potential annual emissions of 76.5 tons of hydrogen chloride.

New process and production units other than the new boiler that are part of this project are not subject to a case-by-case determination of MACT under Section 112(g) of the Clean Air Act. This is because this project is a modification to an existing source, i.e., CWLP's existing power plant on Lake Springfield, for purposes of USEPA's rules governing case-by-case MACT determinations, 40 CFR 63, Subpart B. Under these rules, the other new process and production units that are part of the project would only be subject to case-by-case determinations of MACT if they would constitute major sources of HAPs when considered individually, which is not the case.

C. Federal Control Programs for SO_2 and NOx Emissions from Power Plants

For the new boiler, CWLP would be subject to new requirements for control of SO_2 and NOx emissions that must be developed pursuant to the "Clean Air Interstate Rule" (CAIR), adopted by USEPA in March 2005. Until these new, more stringent requirements take effect, CWLP would be subject to current control requirements for the boiler for an affected unit that have been adopted under Title IV of the Clean Air Act, Acid Deposition, to address SO_2 and NOx emissions from boilers at power plants as related to their contribution to acid rain. Most significantly, CWLP would have to hold SO_2 allowances for the actual SO_2 emissions from the new boiler, as it does now for its existing coal-fired boilers. As the new boiler would also be an Electrical Generating Unit, the new boiler would also be subject to current control requirements under 35 IAC Part 217, Subpart W, the NO_x Trading Program for Electrical Generating Units. This regulatory program was adopted to address the impact of NOx emissions from power plants on attainment of the historic ambient air quality standard for ozone, which applied as a one-hour average. Under this program, CWLP would have to hold NO_x allowances for the actual NO_x emissions of the new boiler during each seasonal control period, as it does for its existing boilers. This program addresses NO_x emissions of all but the smallest power plants in the Midwestern and Eastern United States so that the total seasonal NO_x emissions of these plants remain within the budget established by USEPA for power plants for attainment of the historic ozone standard.

D. Clean Air Act Permit Program (CAAPP)

The existing power plant is a major source under Illinois' Clean Air Act Permit Program (CAAPP), the federal operating permit program for major sources of emissions pursuant to Title V of the Clean Air Act. To address this project, CWLP would have to submit an application to the Illinois EPA for a modification of the CAAPP permit for the plant within 12 months after initial startup of the new boiler.

VI. BEST AVAILABLE CONTROL TECHNOLOGY (BACT)

Under the PSD rules, CWLP must demonstrate that Best Available Control Technology (BACT) will be used to control emissions from the proposed project of pollutants subject to PSD. CWLP has provided a detailed BACT demonstration in its application.

BACT is generally set by a "Top Down Process." In this process, the most effective control option that is available and technically feasible is assumed to constitute BACT for a particular project, unless the energy, environmental and economic impacts associated with that control option are found to be excessive. This approach is generally followed by the Illinois EPA for BACT determinations. In addition to the BACT demonstration provided by an applicant in its permit application, a key resource for BACT determinations is USEPA's *RACT/BACT/LAER Clearinghouse* (Clearinghouse), a national compendium of control technology determinations maintained by USEPA. Other documents that are consulted include general information in the technical literature and information on other similar or related projects that are proposed or have been recently permitted. A summary of the proposed BACT Determination is provided in Attachment 1.

A. BACT Discussion for the Coal-Fired Boiler

Introduction

CWLP has generally explained its rationale for the proposed construction of a pulverized coal boiler in supplementary material submitted to the Illinois EPA on June 27, 2005. This material shows that given CWLP's circumstances, the proposed construction of a new coal-fired boiler is a reasoned response to CWLP's need for new, modern generating capacity.

CWLP is a municipal utility, with a single base-load power plant. This plant is located at a site that is physically constrained by Lake Springfield and by major roadways and commercial and residential development. CWLP is a governmental entity whose function is to supply electricity to residents and businesses located in Springfield. It is not a commercial power company, in competition with other power companies to supply power. These factors greatly restrict CWLP's options for development of new generating capacity, as compared to companies that are in the competitive electric power business.

These circumstances make it impracticable, if not impossible, for CWLP to use Integrated Gasification Combined Cycle (IGCC) technology as an alternative to the proposed project. In addition to overall differences in the cost and reliability of IGCC and boiler technology presently, CWLP is pursuing a project whose size is below that at which costs of IGCC technology would be minimized. Companies that are currently pursuing development of power plants using IGCC technology typically are proposing plants with at least two gasifier trains and a total capacity of more than 500 MW, so as to benefit from economies of scale.

While Circulating Fluidized Bed (CFB) boiler technology could be used for this project, it does not appear to offer significantly different emissions rates or operational advantages for CWLP, as compared to the pulverized coal boiler technology that is planned. In this regard, proposed Dallman Unit 4 would use pulverized coal technology like the three existing Dallman Units that will remain in service at the plant, but equipped with modern emission control technology as appropriate for a new boiler. This control

CWLP also has planned this project to use the same coal supply as the existing Dallman boilers. This is very desirable for CWLP for operational reasons. In addition, the plant property is too small to reasonably accommodate facilities for handling two types of coal. The site also lacks sufficient space to handle low-sulfur Western coal by 100-plus car unit trains direct from a mine. Use of low-sulfur coal also would not result in any meaningful reductions in emissions of pollutants from the project that are subject to PSD. This is because of the emission control technology being required on the new boiler, so that emissions of pollutants subject to PSD must be very effectively controlled independent of the sulfur and content of the coal supply to the boiler.

It is beyond the scope of the BACT determination for the proposed project to consider enhanced energy efficiency and clean energy sources, such as wind turbines or solar power. However, these alternatives would not address CWLP's objective of shutting down and replacing the generating capacity of its existing Lakeside Units. In addition, this project does not prevent CWLP from pursuing these alternatives approaches to meeting the demand for electricity at the same time as the proposed coal-fired boiler assures that CWLP can reliably meet the electricity needs of Springfield.

Emissions of Filterable Particulate Matter (PM)

The particulate matter (PM) emissions from coal-fired boilers can be categorized as either filterable or condensable particulate. The filterable particulate matter exists as a solid or liquid particle in the exhaust of a boiler as it leaves the stack. As such, the filterable PM would be collected by a filter placed in the stack. Condensable particulate is emitted out the stack in a gaseous state but rapidly condenses into particles when released into the atmosphere and cooled. However, due to its gaseous state in the stack, condensable particulate would pass through a filter placed in the stack. There is a long tradition in air pollution control of addressing filterable PM emissions, particularly since many mechanical processes only emit filterable particulate. Concern for condensable PM emissions is a more recent development, with wide-spread recognition of condensable PM generally beginning with USEPA's adoption of the National Ambient Air Quality Standard for PM as PM10 in 1987. Due to the difference in the nature of filterable particulate and condensable particulate, it is appropriate to separately consider BACT for filterable particulate and total particulate, considering both filterable and condensable particulate.

Emissions of filterable PM, also more commonly referred to as fly ash, from coal-fired boilers are controlled by add-on control devices. The two types of control devices that provide high efficiency for filterable PM emissions are electrostatic precipitators (ESP) and fabric filters (baghouses). ESPs remove filterable PM from flue gas by means of electrostatic attraction. Particles in the gas stream are negatively charged by discharge electrodes in the ESP. The charged particles migrate to grounded collecting plates in the ESP. The collected particulate (fly ash) continues to accumulate on the collecting plate, agglomerating together. The accumulated fly ash is periodically removed from the collecting plates, which are oriented vertically, by mechanically shaking or rapping the plates, cleaning only a fraction of the plates in the ESP at any time. The fly ash then falls by gravity into hoppers at the bottom of the ESP for temporary storage pending transfer to longer-term storage and final disposal.

A baghouse controls PM by passing the flue gas through a bank of cloth filter tubes suspended in a housing. Fly ash is deposited on the bag, accumulating until the bag is cleaned. This is performed by either blowing clean air backwards through the bag or a pulse of air to shake the bag. Like ESPs, baghouses for utility boilers are divided into multiple compartments, so that only a small fraction of the baghouse is being cleaned at any time.

Both ESPs and baghouses can provide very effective control of PM emissions, with the selection of the type of control device generally dictated by the design coal supply for a proposed boiler. Baghouses are generally considered more effective when low-sulfur coal is burned. Baghouses are not normally used for control of PM emissions on boilers fired with high sulfur coal, for which ESPs are the preferred control device. This is due to both the nature of the flue gas and fly ash generally produced by the two types of coals. Low-sulfur coal generates flue gas that does not pose significant concern for potential deterioration of the filter bags or the baghouse internals and a fly ash with a high resistivity, which is more difficult to collect in an ESP. High-sulfur generates a flue gas that can pose significant concerns for chronic deterioration of a baghouse and a fly ash with better electrostatic properties for collection by an ESP.

CWLP has selected filtration technology, a baghouse, to control filterable PM emissions from the proposed boiler. CWLP has stated that future requirements for control of mercury emissions were a significant factor in this decision. Boilers equipped with baghouses generally achieve significantly higher levels of mercury removal than boilers equipped with other types of PM control devices. The use of baghouse increases the likelihood that the level of mercury control achieved for the proposed boiler will be sufficient to meet applicable requirements for mercury emissions without the need to install an additional control device for mercury, such as an activated carbon injection system.

CWLP's selection of a baghouse for the boiler has implications for the design of the boiler and its operation, since the boiler will be burning Illinois coal. As compared to use of an ESP, the flue gas entering the baghouse must be hotter so as to maintain the temperature in the baghouse well above the acid dew point temperature, minimize the risk of acid condensation and prevent damage to filter bags and the interior of the baghouse. Additional care will also be required during startup and shutdown down of the boiler and more maintenance effort may be required. However, given that CWLP is prepared to comply with a limit for filterable PM that is identical to the limit that would be set if an ESP were proposed, these consequences from use of a baghouse do not provide a basis for the Illinois EPA to dictate that an ESP must be used for control of filterable PM instead on a baghouse.

The proposed BACT limit is 0.015 lb/million Btu. This limit is consistent with BACT limits that have been set for PM emissions for many new coal-fired boilers and requires very effective control of PM emissions. It provides an appropriate margin of compliance to address the normal variability in performance of a baghouse, as shown by the variation in tested emissions. It also provides a margin of compliance to address the additional variability that may be present given the sulfur content of the coal supply to the boiler. While more stringent limits, e.g., 0.012 lb/million Btu, have been set for certain new utility boilers equipped with baghouses, a lower BACT limit would not provide an adequate compliance margin given the coal supply for the boiler. The permit explicitly addresses the compliance margin by requiring more frequent emission testing for PM emissions if test results are more than 0.10 lb/million Btu.

Total Particulate Matter, including Condensable Particulate Matter

WESP are generally recognized as the appropriate control device for control of condensable PM from coal-fired boilers. This is due to their ability to operate at lower temperatures than either baghouses or ESPs. By their nature, WESPs also can provide additional control of fine filterable particulate, supplementing the removal that is achieved by either ESPs or baghouses.

WESPs operate much the same way as dry ESPs, i.e., electrical charging of the particles or droplets to be collected, migration of the particles to collecting plates, and cleaning of the plates. The difference between the designs of the two types of precipitators lies in the presence of liquid water in a WESP. WESP cleaning is performed by washing the collection surface with water sprays and liquid removal systems employing water, rather than mechanical means such as rapping of the collection plates.

There is a limited body of test data for coal-fired boilers for total PM emissions, including condensable PM emissions. There is even less data available for coal-fired boilers equipped with wet ESPs as the final element in the control train. This is a result of a number of factors, ranging from lack of the necessary testing, the small number of new power plants that are constructed, and the proposed use of WESP on new coal-fired boilers, which is a new development that may be linked to the increasingly more stringent requirements for control of NOx emissions, which necessitates use of SCR systems. Given these circumstances, the Illinois EPA is proposing to proceed cautiously to assure that a limit is set for total PM emissions that is not too low as to not be achievable in practice and not too high so as to not represent the maximum degree of reduction that is achievable.

Another issue for the limit on total PM emissions is the ability to reliably measure condensable particulate emissions. Method 202, the established USEPA method for testing condensable PM has been shown to overstate emissions due to the contribution of "artifacts" created in the sampling apparatus. The creation of these artifacts due to conversion of SO_2 to SO_3 or other chemical reactions in the sampling apparatus is a valid concern, as collected pollutants are present in solution at higher concentrations and for a longer period than exist in the atmosphere immediately after discharge to the atmosphere. The magnitude of these effects has not been adequately quantified, since they are influenced of concentration of various pollutants in the flue gas. In addition, Method 202 accommodates variation in the testing procedures to reflect differences in state and local agency practices with respect to the scope of condensable particulate. This means that not only must emission limits be set that accommodate the potential for great variability or inaccuracy in future test result, but that caution should be exercised when acting on the results of historic tests for condensable particulate.

Accordingly, a BACT limit is proposed, 0.035 lb/million Btu, that is believed to be readily achievable. The limit is identical to the limit set for the Prairie State project. Assuming an actual emission rate of 0.010 lb/million Btu, for filterable PM, this would allow condensable PM emissions of 0.025 lb/million Btu.

A number of recently permitted new utility boilers , including WEPCO-Elm Road, Longview, Thoroughbred and Plum Point Energy, have total PM emission limits set at 0.018 lb/million Btu. While the permitting authorities in these other states have established this limit for total PM, the Illinois EPA does not believe that there is an adequate basis upon which to establish such a limit for the proposed boiler. The lower limits for total PM set for these other projects, by themselves certainly do not provide an adequate basis to set such a limit for the proposed boiler. However, none of these boilers are built and operating yet and these limits have not been shown to be achievable in practice.

The limits set as BACT for sulfuric acid mist emissions for these other project are comparable to the limit being proposed for sulfuric acid mist for the proposed boiler. As sulfuric acid mist is a major component of condensable PM emissions from coal-fired boilers, sulfuric acid mist serves as a surrogate pollutant for condensable PM. The imposition of a similar limit for sulfuric acid mist emissions from the proposed boiler should assure that the emission rate for condensable PM from the proposed boiler is similar to that being required of other new boiler projects.

Finally, these other projects do provide relevant data to set a target for the limit for total PM emissions for the proposed boiler. If an emission rate of 0.018 lb/million Btu can be reliably achieved for total PM emissions from the proposed boiler, as demonstrated by a series of tests, final BACT limit would be set at this level without attempting to determine whether an even lower limit might be achievable.

Emissions of Carbon Monoxide (CO)

Carbon monoxide (CO) emissions are the result of incomplete combustion. The available control methods are: 1) Increased excess air and 2) Design of the combustion process and good combustion practices to minimize the formation of CO. Add-on control devices are not used to control CO emissions from coal-fired boilers.

Increasing the levels of excess air introduced into the boiler, above the level that would otherwise be present for proper operation of the boiler, could theoretically reduce CO emissions of a boiler by raising the amount of oxygen available to complete oxidation of CO into CO_2. However, this technique would have the adverse effect of increasing emissions of other pollutants. It would increase NO_x emissions, as much of the NOx is formed thermally, due to the combination of nitrogen and oxygen in the combustion air in the flame, rather than from nitrogen in the fuel. This reaction is facilitated by excess air, as it provides more oxygen to participate in this reaction. More generally, increased excess air would reduce the energy efficiency of a boiler, requiring consumption of additional fuel with accompanying emissions, to produce the needed amount of electrical power. Generating additional NOx, PM, and SO_2 emissions to reduce CO emissions is an unacceptable consequence of employing excess air. For these reasons, high excess air levels has not been selected as BACT for CO emissions.

As a practical matter, CO emissions from the proposed coal-fired boiler can be effectively minimized by relying on good combustion practices, i.e., careful management of the combustion process for essentially complete combustion. A properly operated boiler effectively functions as a thermal oxidizer. For the proposed boiler, a more stringent limit for CO emissions, achieved with additional excess air would be counterproductive given the need to reduce NO_x emissions. Generally, CO emissions from the boiler are inversely related to NO_x emissions. A CO emission limit less than 0.12 lb million Btu on the proposed boiler would unduly restrict further NO_x reductions, which are typically of greater importance than CO reductions.

Proper boiler design and operation with good combustion practices will provide appropriate control of CO emissions from the new boiler. The proposed BACT limit is 0.12 lb/million Btu, which is consistent with the BACT limits set for other recently permitted coal-fired utility boiler projects. This limit provides CWLP with a reasonable ability to minimize formation of NOx using low-NOx combustion technology. It also provides an appropriate margin of compliance to account for normal variation in the operation of the boiler. This compliance margin would essentially be codified by the permit, which requires that CWLP conduct continuous emissions monitoring for CO if tested emissions are greater than 0.09 lb/million Btu, i.e., greater than 75 percent of the limit set as BACT.

Emissions of Sulfuric Acid Mist

In a coal-fired boiler, a small amount of the sulfur in the coal is converted into sulfuric acid mist, rather than SO_2. This process is similar to the reaction in the atmosphere of much of the SO_2 emitted from the boiler, as the SO_2 gradually reacts to form sulfates. The formation of sulfuric acid mist in a coal-fired boiler is increased by the presence of an SCR system, as the catalyst also facilitates the reaction of SO_2 to SO_3, which then reacts with water to form sulfuric acid mist. While sulfuric acid mist is recognized as a separate pollutant, it also constitutes a major component in the condensable particulate matter emissions from a coal-fired boiler.

There are three basic options for control of sulfuric acid mist emissions from a coal-fired boiler: co-removal with SO_2 scrubbing, sorbent injection, and use of a wet electrostatic precipitator (WESP). Scrubbing for SO_2 also provides control of sulfuric acid mist by absorbing the mist in the alkaline scrubbant. However, scrubbers are not as effective for sulfuric acid mist as for SO_2. This is because the sulfuric acid mist is present as very fine droplets, rather than as a gas. Accordingly, only a moderate level of control can be relied upon.

With sorbent injection, chemical reagents are introduced into the boiler at various point(s) in either powder form or as a liquid solution to absorb sulfuric acid mist. The sorbent is subsequently collected as PM by the PM control device. Materials such as magnesium oxide, calcium oxide, organic amines, ammonia, and sodium bisulfite have all worked to reduce sulfuric acid emissions. Some of the more economical options are the injection of ammonia or hydrated lime downstream of the air heater or sodium bisulfate injection upstream or downstream into ductwork of the air heater. Sorbent injection is most commonly used as an operational practice on a boiler to protect the interior of a boiler from corrosion, especially the air preheater, which is the final step in the boiler, rather than as a means to control emissions. Accordingly, it is often used in conjunction with the installation of an SCR if needed to counter the additional sulfuric acid mist created as a result of the SCR. However, sorbent injection for control can also be affective for control of emissions of sulfuric acid achieving levels of control that are achieved with a WESP, as discussed below.

WESPs are the established control technique for emissions of sulfuric acid mist from acid production plants and chemical processes that generate sulfuric acid mist. As already discussed, in addition to controlling sulfuric acid mist, WESPs also provide additional control of fine filterable particulate, emissions acid gases sulfuric acid mist that are present in the exhaust in very small droplets of water, and control for condensable particulate.

Give the multiple benefits of a WESP, the BACT limit for sulfuric acid mist is based on use of a WESP. The proposed BACT limit that is 0.005 lb/million Btu. This is a stringent limit that is in line with the BACT limits set for other recently permitted new coal-fired utility boilers.

Startup and Shutdown

Compliance with the above BACT limits, which are expressed in lb/million Btu, is intended to be demonstrated by periodic emission testing and proper operation and work practices between tests, as confirmed by opacity monitoring, operational monitoring, and recordkeeping. This approach does not assure that compliance with these rate-based BACT limits can be reasonably determined during startup and shutdown of the boiler. This is because it is impractical to conduct emissions testing during such events. Startups and shutdowns of the boiler are expected to be infrequent events given the new boiler's role in providing base-load power. It would be unrealistic to expect such events could be successfully coordinated with the availability of personnel and equipment to conduct emissions testing. In addition, the applicable USEPA Reference Methods for emissions testing are generally developed to provide reliable measurements during stable operation of an emission unit. Emission testing actually entails three separate one-hour test runs, with the measured emission rate determined as the average of the individual test runs. Accordingly, even if an emission test could be scheduled during a startup or shutdown, it would not provide useful data to determine compliance. Each run of the test would be for a different segment of the transitory conditions during the startup or shutdown of the boiler. As such, it would be inappropriate to average the data from the individual test runs and the data from any individual test run could not be relied upon by itself.

These circumstances are of particular importance for CO emissions, since good combustion practices are being used to control CO emissions. The effectiveness of these practices will vary as air flow rates into the boiler go up or down, burners are brought into or taken out of service, and furnace temperatures vary during the startup and shutdown of the boiler. The CO BACT limit of 0.12 lb/million Btu that can be reliably achieved when the boiler is being fired at 2,000 million Btu/hour, cannot be assured when the boiler is fired at only 20 or 200 million Btu/hour during the course of a startup or shutdown event, even as the CO emissions stay within the permitted hourly rate. They are of less concern for PM and sulfuric acid mist, as emissions of these pollutants are controlled by add-on control devices whose effectiveness should be less dramatically affected by the transitory operating conditions of the boiler during startup and shutdown, if they are affected at all. Nevertheless, the available measurement methodology for testing emissions of these pollutants also makes it infeasible for compliance with limits expressed in lb/million Btu to be determined during startup and shutdown events.

Given these circumstances, the BACT limits expressed in lb/million Btu would not apply during startup and shutdown of the boiler. Instead, CWLP must first carry out startup and shutdown of the boiler in a manner that minimizes emissions, in accordance with written procedures that meet certain specific requirements set forth in the permit, such as appropriate use of natural gas during such events. Second, the limits on emissions of the boiler expressed in lb/hour, which would continue to apply during periods of startup and shutdown, would serve as "secondary" BACT limits. Since testing will not be feasible to empirically demonstrate compliance with such limits, compliance will have to be determined by means of engineering analysis and evaluation. However, such engineering evaluation will be far more practical to perform, and to be reviewed, for limits expressed in lb/hour, rather than in lb/million Btu, as would have to be attempted if the "basic" BACT limits applied during startup and shutdown events. Finally, as the hourly emission limits set for the boiler continue to apply during such events, CWLP would also have to include and account for emissions during such events when it determines compliance with the annual emission limits set for the boiler.

For emissions of PM, this situation is not altered by the fact that CWLP must conduct continuous emissions monitoring for PM emissions from the boiler. Continuous monitoring of PM emissions from boilers has not yet been demonstrated to be sufficiently reliable that the Illinois EPA is prepared to mandate that CWLP use PM monitoring to determine compliance with applicable limits for filterable PM emissions during regular operation of the boiler. (Current PM monitoring systems only measure filterable PM, and do not account for condensable PM emissions, which is present in the flue gas in a gaseous state.) Instead PM continuous emissions monitoring is being required for purposes of compliance assurance monitoring, to provide additional operational data related to the overall operation of the control train on the boiler that will assist in assuring that the control equipment is properly operated and maintained. It would do this by alerting CWLP to possible abnormal operation, for which CWLP would have to undertake an investigation, followed by any appropriate corrective action. To use monitoring to directly determine compliance requires that the monitor provide data of very high reliability. Essentially, the need for an investigation is eliminated and the source must immediately undertake corrective action, proceeding as if it were not in compliance. This dictates a very high standard for the demonstration that a continuous monitor can be relied upon to determine compliance. Finally, even if PM continuous emission monitoring is demonstrated to provide reliable data for regular operation of the boiler, this does not show that it would provide reliable data for startup and shutdown of the boiler. This is because accuracy of PM continuous emissions monitoring is evaluated by comparison to simultaneous measurements of PM made by emissions testing. If the test methods are not reliable during the transitory operating conditions of startup and shutdown, as already discussed, this means that the reliability of continuous monitoring during those events cannot be directly confirmed.

B. BACT Discussion for Other Units

In its application, CWLP also addresses BACT for other emission units that are part of the proposed project. Appropriate control measures are proposed

PM emissions from handling of coal, ash, limestone and gypsum will be effectively controlled in a variety of ways. These include use of baghouses or other appropriate control devices and implementation of other control measures to effectively control direct "process" and fugitive emissions from these operations. The emission control requirements are accompanied by compliance procedures that are appropriate for the type of control measures that are applied to the different material handling operations, including provisions for regular inspections by appropriate personnel, periodic observations of opacity and visible emissions, recordkeeping, and emission testing if and as needed.

PM emissions from the cooling tower will be controlled by use of high-efficiency drift eliminators, designed to maintain drift loss to no more than 0.0005 percent. Dry cooling is an alternative to the wet cooling tower proposed as part of this project. Dry cooling is typically used at power plants located in arid regions where water resources are very limited and the relative humidity is low. This does not demonstrate that dry cooling is appropriate for this project, which is not located in an arid region. This is because of the additional power required by dry cooling and its effect on the energy efficiency and overall emissions of the proposed project. Accordingly use of high-efficiency drift eliminators has been selected as BACT for the cooling tower.

Fugitive dust control for new roadways and open areas associated with this project must be controlled by appropriate application of water or other dust suppressants. In addition, regularly traveled roads and roadways must be paved and be subject to treatment for effective control of dust from paved roads. The required fugitive dust control program is accompanied by requirements for recordkeeping to confirm that the program is properly implemented.

VII. MAXIMUM ACHIEVABLE CONTROL TECHNOLOGY (MACT)

As previously explained, while a case-by-case MACT determination is not necessary for the proposed boiler at this time, the draft permit contains a case-by-case MACT determination to address the possibility that USEPA's finding with respect to regulation of HAP emissions from utility steam generating units is overturned. This determination addresses the three "classes" of HAPs emitted from coal-fired boilers, i.e., mercury, acid gases, and organic HAPs. This determination does not address emissions of other metals from the boiler, which are addressed by the BACT determination for PM emissions.

<u>Mercury</u>

Emissions of mercury are addressed individually because of the nature of mercury, which is normally emitted in gaseous form from a boiler, unlike other metals, which are present as particulate. The proposed MACT determination for mercury for the proposed boiler is based upon the information on mercury emissions presented in the application and review of information prepared by USEPA and others about control of mercury emissions from coal-fired utility boilers. This material indicates that mercury emissions from coal-fired boilers may be very effectively controlled by "co-benefit" when certain combinations of control devices are used to control emissions of other pollutants from a boiler. The combination of SCR, baghouse, and scrubbing, as proposed by CWLP for the proposed boiler, is one such combination of control devices. Emissions of mercury can also be very effectively controlled by introduction of a sorbent material, usually activated carbon, into the flue gas. Accordingly, the MACT determination for the proposed boiler establishes two technology-based alternatives as MACT for the boiler, either effective mercury control as a result of co-benefit or effective use of a sorbent injection system specifically for control of mercury emissions.

Under the first alternative, the emission control measures used for the boiler would have to achieve a mercury control efficiency of at least 95 percent by co-benefit, without injection of activated carbon or other similar material specifically for control mercury emissions. Some consideration would be allowed for washing of the raw coal at the mine in determining the effectives of control. The remainder of the emissions control would have to be achieved by co-benefit at the boiler. This approach is being taken because washing of raw coal is effective in lowering the mercury content of the product coal, as well as removing non-combustible material and increasing the heat content of the shipped coal. In addition, mercury emissions are being limited in terms of an emission rate, i.e., lb/million Btu input or lb/GWh output, so that consideration of the effect of coal washing would be inherent in the form of the emission standard. For this purpose of considering the effect of coal washing, the nominal level of removal proposed for conventional washing of coal, as is currently conducted for the coal being used by CWLP, is conservatively set at 25 percent. If an enhanced coal washing process were to be introduced to specifically target removal of mercury, a higher value for the nominal control efficiency provided by the coal washing process could be set. This would occur on a case-by-case basis following an evaluation of the levels of mercury removal that are being achieved by such process.

Under the second alternative, powdered activated carbon or other similar sorbent material would have to be used for the maximum practicable degree of mercury removal. The required level of mercury injection would be determined from an evaluation of the effectiveness of the sorbent injection system installed on the boiler. This evaluation would identify the rates of sorbent injection into the boiler that assure that ample amounts of sorbent are present in the flue gas to collect mercury.

Hydrogen Chloride

The hydrogen chloride emission limits were determined from information on hydrogen chloride emissions in the application and review of other information and information prepared by USEPA about control of hydrogen chloride emissions from coal-fired boilers. The limits are based on the scrubber and WESP used for control of SO_2 and sulfuric acid mist emissions from the boiler also providing effective control of hydrogen chloride emissions. To account for potential variability in the trace chlorine levels in the coal supply to the boiler, which would affect the level of hydrogen chlorine in the flue gas, limits are proposed in terms of both emission rate and control efficiency. The limit selected for the emission rate alternative is 0.020 lb/million Btu, which is the emission limit set by USEPA as MACT for coal-fired industrial boilers. The limit selected for the control efficiency alternative is 97.5 percent, which reflects effective operation of the control system for control of hydrogen chloride emissions.

Volatile Organic Material

VOM emissions are addressed in the proposed MACT determination as VOM serves as a surrogate for emissions of organic HAPs, which are the fourth class of HAPs emitted by coal-fired boilers. The limit for VOM emissions is based on use of good combustion practices to minimize emissions, as would also be used for emissions of CO. The selected limit reflects a review of the BACT limits set for other new coal-fired utility boilers that are subject to PSD for VOM emissions, to set a stringent limit for VOM emissions from the proposed boiler.

VIII. AIR QUALITY ANALYSIS

A. Introduction

The previous discussion addressed emissions and emission standards. Emissions are the quantity of pollutants emitted by a source, as they are released to the atmosphere from a stack. Standards are set limiting the amount of these emissions primarily as a means to address the quality of air. The quality of air as we breathe it or as plants and animals experience it is known as ambient air quality. Ambient air quality considers the emissions from a particular source after they have dispersed following release from a stack, in combination with pollutant emitted from other nearby sources and background pollutant levels.

The concern for pollutants in ambient air is typically expressed in terms of the concentration of the pollutant in the air. One form of this expression is parts per million. A more common scientific form is microgram per cubic meter, i.e. a millionth of a gram in a cube of air one meter on a side.

The United States EPA has established standards, which set limits on the level of pollution in the ambient air. These ambient air quality standards are based on a broad collection of scientific data to define levels of ambient air quality where adverse human health impacts and welfare impacts may occur. As part of the process of adopting air quality standards, the United States EPA compiles the various scientific information on impacts into a "criteria" document. Hence the pollutants for which legal air quality standards exist are known as criteria pollutants. Based upon the nature and effects of a pollutant, appropriate numerical limitation(s) and associated averaging times are set to protect against adverse impacts. For some pollutants several standards are set, for others only a single standard has been established.

Areas can be designated as attainment or nonattainment for criteria pollutants, based on the existing air quality. Areas in which the air quality standard is met for a pollutant are known as attainment. If the air quality standard is exceeded, the area is known as nonattainment.

Given the geographic extent of areas designated as nonattainment and the USEPA's process for redesignating an area to attainment, the air quality in some or all of an area designated as nonattainment may actually be in compliance with the relevant air quality standard.

In attainment areas one wishes to generally preserve the existing clean air resource and prevent increases in emissions, which would result in nonattainment. In a nonattainment area efforts must be taken to reduce emissions to come into attainment. An area can be attainment for one pollutant and nonattainment for another.

Compliance with air quality standards is determined by two techniques, monitoring and modeling. In monitoring one actually samples the levels of pollutants in the air on a routine basis. This is particularly valuable as monitoring provides data on actual air quality, considering actual weather and source operation. The Illinois EPA operates a network of ambient monitoring stations across the state.

Monitoring is limited because one cannot operate monitors at all locations. One also cannot monitor to predict the effect of a future source, which has not yet been built, or to evaluate the effect of possible regulatory programs to reduce emissions. Modeling is used for these purposes: Modeling uses mathematical equations to predict ambient concentrations based on various factors, including the height of a stack, the velocity and temperature of exhaust gases, and weather data (speed, direction and atmospheric mixing).

Modeling is performed by computer, allowing detailed estimates to be made of air quality impacts over a range of weather data. Modeling techniques are well developed for essentially stable pollutants like particulate matter, NO_x, and CO, and can readily address the impact of individual sources. Modeling techniques for reactive pollutants, e.g., ozone, are more complex and have generally been developed for analysis of entire urban areas. They are not applicable to a single source with small amounts of emissions.

Air quality analysis is the process of predicting ambient concentrations in an area or as a result of a project and comparing the concentration to the air quality standard or other reference level. Air quality analysis uses a combination of monitoring data and modeling as appropriate.

B. Air Quality Analysis

An ambient air quality analysis was conducted by a consulting firm, Burns & McDonnell, on behalf of CWLP to assess the air quality impacts of the proposed project due to its PM, CO and sulfuric acid mist emissions, the pollutants that are subject to PSD. Under the PSD rules, this analysis must demonstrate that the proposed project will not cause or contribute to a violation of any applicable air quality standard or PSD increment.

The following tables summarize the results of the air quality analysis conducted for the proposed project. The initial analysis necessary for this project under the PSD rules evaluated whether the proposed project would have "significant impacts" for CO and PM, the criteria pollutants that are subject to PSD. In its guidance for the performance of PSD air quality analyses, USEPA has established Significant Impact Levels for different pollutants. If modeled impacts of a project are above the level for a pollutant, a more refined air quality analysis is required under the PSD rules. This more refined analysis must also address existing emission units at the source at which a project is located and other large stationary sources in the surrounding area, in addition to the proposed project. The significant impact levels are a fraction of the applicable National Ambient Air Quality Standards for a pollutant, which are the threshold levels set by USEPA for health and welfare effects from a pollutant. The significant impact levels also do not correspond to threshold levels for effects on flora or fauna from a pollutant.

The initial analysis conducted for the proposed project shows that the impacts for CO air quality are well below the significant impact levels set for CO. Because the maximum CO impacts did not exceed the significant impact levels, no additional modeling was performed to address CO emissions from start-up of the boiler on the CO NAAQS, which apply as a 1-hour and 8-hour average. However, the maximum* predicted impacts of the project for PM10 were greater that the significant impact levels, on both a short term and annual basis. Therefore, further modeling was required to address both the consumption of PSD Increments and the protection of the PM10 ambient air quality standards. These maximum impacts are largely attributable to the PM emissions from units other than the new boiler, which are released at or near ground level. As part of this analysis, modeling was conducted for the new boiler at 100, 75, 50, and 25 percent loads. This reduced load analysis was conducted to account for weather conditions during which air quality impacts are higher at reduced load, due to reduced exhaust velocity and lower effective plume height from the boiler. The predicted air quality impacts of the boiler at reduced loads were also considered when the maximum impacts of the project were being identified.

Table 1. Significant Impact Modeling (ug/m^3)

Pollutant	Averaging Period	Maximum Predicted Impact	Significant Impact Level
PM10	24-hour	29.9	5
	Annual	5.5	1
CO	1-hour	296.0	2000
	8-hour	60.8	500

One part of the refined air quality analysis for PM10 involves modeling the proposed project and all other new units in the area that consume PSD increment to determine whether the PSD increment will be consumed. This analysis was done with an inventory of increment consuming source supplied by IEPA. The results of the increment consumption modeling, as provided below, show that this project will not result in an exceedance of the PM10 increments.

Table 2: PM10 Increment Consumption (ug/m^3)

Averaging Period	Maximum* Increment Consumed	Applicable Increment
24-Hour	26.9	30
Annual	5.5	17

* The maximum air quality impacts are determined using the appropriate procedure for consistency with the applicable measure of air quality impact, as follows: Highest 1st high for the annual increment and highest 2nd high for the daily increment.

The other part of the refined air quality analysis for PM10 involved modeling to confirm that the National Ambient Air Quality Standards (NAAQS) for PM10 is protected. This modeling combines with the maximum modeled impacts for the PM10 emissions of the proposed project, the existing power plant and other large sources in the area, with representative background concentrations. Background values were taken data collected in 2001, 2002 and 2003 at the ambient monitoring station in Nilwood, the station nearest to Springfield at which PM10 is monitored. The results of this analysis, as provided below, show that the proposed project will not cause or contribute to violations of the applicable NAAQS.

Table 3: Results of the NAAQS Analysis for PM10 (ug/m^3)

Averaging Period	Maximum* Modeled Impact	Monitored Background	Total Impact	NAAQS
24-Hour	86.0	63.0	149.0	150
Annual	24.0	19.3	43.3	50

* The maximum air quality impacts are determined using the appropriate procedure for consistency with the applicable measure of air quality impact, as follows: Highest average of annual data for five years for the Annual NAAQS, and 6th high in five years for the Daily NAAQS.

The modeling conducted by CWLP also allows an assessment of the impact of the proposed project on compliance with the PM2.5 NAAQS, based on the emissions of the boiler, which is the key unit for purposes of PM2.5 air quality. The maximum PM 2.5 impacts of the boiler are predicted as 1.82 ug/m^3, 24-hour average. While USEPA has not yet set significant impact levels for PM2.5, the maximum daily impact is below the applicable significant impact level set by USEPA for PM10. The impact of the boiler on an annual basis would be a fraction of this level, no more than 0.2 ug/m^3, which would be less than the 1.0 ug/m^3 significant impact level for PM10 on an annual basis. Current air quality data for Springfield is available from the ambient monitoring station operated by the Illinois EPA at the State Fairgrounds. When these maximum predicted PM2.5 impacts from the boiler are combined with the current air quality data, compliance is still shown with the PM2.5 NAAQS (65 ug/m^3 and 15 ug/m^3).

Table 4: Monitored PM2.5 Air Quality Data for Springfield (ug/m^3)

Year	Highest Daily Concentrations (24-hour)				Annual Concentration	
	1st	2nd	3rd	4th	Year	3-Year Ave
2005	44.8	38.5	37.0	36.6	15.1	13.5
2004	35.8	32.9	30.2	25.6	11.8	12.9
2003	34.1	33.3	31.5	30.3	13.6	13.4
2002	41.1	34.0	33.3	31.9	13.3	-
2001	33.8	32.9	32.2	28.7	13.4	-

CWLP also conducted modeling for the sulfuric acid mist emissions from the project. The maximum predicted impact was 0.26 ug/m^3, 24-hour average.

USEPA has not established either NAAQS or PSD Increments for sulfuric acid mist.

C. Other Air Quality Related Impacts

Under the PSD rules, CWLP must also submit analyses to address changes in air quality from growth in the area that result from the project, and construction of the source itself. It must also evaluate the potential for visibility impairment and address the potential impacts on soil and vegetation.

CWLP provided an additional impact analysis discussing the emissions impacts resulting from residential and commercial growth associated with the proposed project. Anticipated residential and commercial growth associated with construction and operation of the new boiler is expected to be low, as are the emissions resulting from this growth. Most impacts would be temporary, resulting from the work force required during the construction phase. CWLP predicts that the number of additional permanent employees needed for operation of the boiler will be about 20. This would only result in additional secondary employment and associated economic activity if these positions could not be filled from the current work force in the Springfield area. The secondary air emissions (i.e., e.g., increased vehicle traffic) from construction activity and any long-term growth are not expected to significantly impact air quality in the Springfield area or in the immediate vicinity of the plant.

CWLP's air quality consultant, Burns and McDonnell, provided an additional analysis to evaluate potential impacts to vegetation and soils. Modeling was performed to determine maximum impacts of arsenic, cadmium, chromium, cobalt, fluorides, lead, manganese, mercury, nickel, and selenium. Maximum impacts were compared to screening levels found in the USEPA's *A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animal*, EPA 450/2-81-078. The screening values in this USEPA guidance document address direct impacts on soils and plants, and the effects on animals consuming the plants. The modeled impacts were all well below the appropriate screening levels for all indicators.

A visibility analysis was also prepared for potential impacts on the two nearest PSD Class I Areas, the Wilderness Area at the Mingo National Wildlife Refuge in Missouri, and Mammoth Cave National Park in Kentucky, both of which are located over 300 kilometers from Springfield. The analysis conforms to USEPA visibility guidance, including the use of the VISCREEN model with worst-case meteorology. The results show that the proposed facility will not cause perceivable visibility degradation at either area.

An analysis of potential impacts of fogging and icing from the proposed cooling tower was prepared by TRC Environmental on behalf of CWLP. This analysis was specifically requested by the Illinois EPA because of concern about the potential impact of the cooling tower on visibility and driving conditions on nearby Interstate 55. The results of this analysis indicate that fogging and icing will not occur off of plant property for any of the plume abatement designs considered and should not pose safety concerns for traffic on the nearby highway.

IX. REQUEST FOR COMMENTS

It is the Illinois EPA's preliminary determination that the draft permits would meet all applicable state and federal air pollution control requirements, subject to the conditions in the draft permit.

Attachment 1 - Summary of Proposed BACT Determinations

Boiler:

Pollutant	Emission Limits (lb/million Btu)	Principal Control Measures
PM	Filterable - 0.015 Total - 0.035	Baghouse and Wet Electrostatic Precipitator
CO	0.12	Good Combustion Practices
Sulfuric Acid Mist	0.005	Scrubber and Wet Electrostatic Precipitator

Bulk Material Handling and Other Operations:

Operation	PM Limitation	Control Measures
Handling of Coal And Other Dry Materials	Fugitives - No visible emissions Process (stack)- 0.01 grain/dscf	Dust Suppression, Enclosure and Baghouses, Filters and Other Approved Control Devices
Storage Buildings	No visible emissions	Enclosure, Dust Suppression and Control Devices
Storage Piles	No visible emissions or 90 percent control (98 percent for limestone)	Work Practices and Dust Suppression
Existing Receiving Operations	10 percent opacity Process (stack)- 0.01 grain/dscf	Material Quality and Enclosure
Cooling Tower	Design drift rate no more than 0.0005 percent	High-Efficiency Drift Eliminators
Roadways and Open Areas	-	Paving and Fugitive Dust Control Program

EXHIBIT 4

217/782-2113

CONSTRUCTION PERMIT - PSD APPROVAL
NSPS-NESHAP EMISSION UNITS

PERMITTEE

Indeck-Elwood LLC
Attn: Mr. James Schneider
600 N. Buffalo Grove Road
Buffalo Grove, Illinois 60089

Application No.: 02030060 I.D. No.: 197035AAJ
Applicant's Designation: Date Received: March 21, 2002
Subject: Electricity Generation Facility
Date Issued: October 10, 2003
Location: Southwest of the Intersection of Drummond and Baseline Roads, Elwood, Will County

Permit is hereby granted to the above-designated Permittee to CONSTRUCT emission source and air pollution control equipment consisting of an electric power plant with two circulating fluidized bed boilers, fuel handling and storage, limestone handling and storage, ash handling and storage, cooling towers, auxiliary gas-fired boiler, and ancillary operations, as described in the above referenced application. This Permit is granted based upon and subject to the findings and conditions that follow.

In conjunction with this permit, approval is given with respect to the federal regulations for Prevention of Significant Deterioration of Air Quality (PSD) for the plant, as described in the application, in that the Illinois Environmental Protection Agency (IEPA) finds that the application fulfills all applicable requirements of 40 CFR 52.21. This approval is issued pursuant to the Clean Air Act, as amended, 42 U.S.C. 7401 et seq., the federal regulations promulgated thereunder at 40 CFR 52.21 for Prevention of Significant Deterioration of Air Quality (PSD), and a Delegation of Authority agreement between the United States Environmental Protection Agency (USEPA) and the Illinois EPA for the administration of the PSD Program. This approval becomes effective in accordance with the provisions of 40 CFR 124.15 and may be appealed in accordance with provisions of 40 CFR 124.19. This approval is based upon the findings that follow. This approval is subject to the following conditions. This approval is also subject to the general requirement that the plant be developed and operated consistent with the specifications and data included in the application and any significant departure from the terms expressed in the application, if not otherwise authorized by this permit, must receive prior written authorization from the Illinois EPA.

If you have any questions on this permit, please call Shashi Shah at 217/782-2113.

Donald E. Sutton, P.E.
Manager, Permit Section
Division of Air Pollution Control

DES:SRS:jar

cc: Region 1
USEPA Region V

TABLE OF CONTENTS

SECTION 1: FINDINGS

1a. Indeck-Elwood LLC (Indeck) has requested a permit for a coal fired power plant with a nominal capacity of 660 MWe gross. The proposed plant would have two identical circulating fluidized bed (CFB) boilers equipped with limestone injection to the bed, selective noncatalytic reduction (SNCR), and a baghouse. Ancillary operations would include coal handling and storage; ash handling and storage; limestone handling and storage; cooling tower; auxiliary boiler, and other ancillary operations.

b. The boilers, which each would have a maximum rated capacity of about 2900 million Btu/hour, would be fired on coal as their primary fuel and petroleum coke and coal tailings as supplemental fuels, with natural gas used as the startup fuel. The boilers would generally be designed for coal mined in Illinois that, prior to being washed, would nominally have 3.51 percent sulfur by weight and 9,965 Btu per pound higher heating value (HHV), which is equivalent to an uncontrolled sulfur dioxide emission rate of 7.0 pounds per million Btu heat input. The washed coal would have an equivalent uncontrolled sulfur dioxide emission rate of approximately 4.7 pounds per million Btu.

2. The plant would be located on an approximately 130-acre site near Elwood in Will County. The site is in an area that is currently designated nonattainment for ozone and attainment for all other criteria pollutants.

3. The proposed plant is a major source under the PSD rules. This is because the CFB boilers, as indicated in the application, would have potential annual emissions of sulfur dioxide (SO_2), nitrogen oxides (NO_x), particulate matter (PM), and carbon monoxide (CO) that are each in excess of 100 tons. The plant would also have the potential to emit significant amounts of sulfuric acid mist, fluorides, and beryllium. (Refer to Table I for the potential emissions of the CFB boilers.)

4. The proposed plant is a major source under Illinois's rules for nonattainment new source review, Major Stationary Sources Construction and Modification (MSSCAM), 35 IAC Part 203. This is because the plant would be located in an area that is designated nonattainment for ozone and, as indicated in the application, would have potential annual emissions of volatile organic materials (VOM) that are in excess of 25 tons. As the plant would be located in an ozone nonattainment, conditions of this construction permit as they relate to emissions of VOM are not considered part of the PSD approval.

5. The proposed plant is a major source for emissions of hazardous air pollutants (HAP). The potential HAP emissions from the plant will be greater than 10 tons of an individual HAP, i.e., hydrogen chloride and hydrogen fluoride. Therefore, the plant is being subjected to review under Section 112(g) of the Clean Air Act.

6. After reviewing the materials submitted by Indeck, the Illinois EPA has determined that the project will (i) comply with applicable Board emission standards (ii) comply with applicable federal emission standards, (iii) utilize Best Available Control Technology (BACT) on emissions of pollutants as required by PSD, (iii) achieve the Lowest Achievable Emission Rate (LAER) for emissions of VOM as required by 35 IAC Part 203, and (v) utilize Maximum Achievable Control Technology (MACT) for emissions of HAP as required by Section 112(g) of the Clean Air Act.

The determinations of BACT, LAER and MACT made by the Illinois EPA for the proposed plant are the control technology determination contained in the permit conditions for specific emission units. For this purpose, limits related to VOM emissions constitute LAER and limits related to hazardous air pollutants emissions constitute

MACT. As limits are not present for specific hazardous air pollutants, the MACT determination relies upon the limits established for other pollutants to also restrict emissions of the hazardous air pollutants for which individual limits are not set. If USEPA were to adopt a MACT regulation that is applicable to the plant that establishes a standard that is more stringent than a standard set as MACT by this permit, the Permittee would be required to comply with such new standard as expeditiously as practicable, with an appropriate compliance date set by the Illinois EPA, pursuant to 40 CFR 63.44(b)(2).

7. The air quality analysis submitted by Indeck and reviewed by the Illinois EPA shows that the proposed project will not cause violations of the ambient air quality standard for NO_x, SO_2, PM/PM_{10}, and CO. The air quality analysis shows compliance with the allowable increment levels established under the PSD regulations.

8. The analysis of alternatives to the project submitted by Indeck shows that the benefits of the proposed plant outweigh the potential impacts of its emissions of VOM, as required by 35 IAC 203.306.

9. The Illinois EPA has determined that the proposed plant complies with all applicable Illinois Pollution Control Board Air Pollution Regulations; the federal Prevention of Significant Deterioration of Air Quality Regulations (PSD), 40 CFR 52.21; applicable federal New Source Performance Standards (NSPS), 40 CFR 60; and Section 112(g) of the Clean Air Act and applicable federal regulations thereunder, National Emission Standards for Hazardous Air Pollutants (NESHAP) 40 CFR 63, Subpart B.

10. In conjunction with the issuance of this construction permit, the Illinois EPA is also issuing an Acid Rain permit for the proposed CFB boilers, to address requirements of the federal Acid Rain program. These CFB boilers would be affected units under the Acid Rain Deposition Control Program pursuant to Title IV of the Clean Air Act. As affected units under the Acid Rain Program, Indeck must hold SO_2 allowances each year for the actual emissions of SO_2 from the CFB boilers. The CFB boilers are also subject to emissions monitoring requirements pursuant to 40 CFR Part 75. As the Acid Rain permit relates to the Acid Rain Program, it is not considered part of the PSD approval.

11. In conjunction with the issuance of this construction permit, the Illinois EPA is also issuing a Budget Permit for the proposed CFB boilers, to address requirements of the federal Acid Rain program and the NO_x Trading Program. As the Budget Permit relates to the NO_x Trading Program, it is not considered part of the PSD approval.

12. A copy of the application, the project summary prepared by the Illinois EPA, a draft of this construction permit, and a draft of the Acid Rain and Budget permits were placed in public locations near the plant, and the public was given notice and an opportunity to examine this material and to participate in a public hearing and to submit comments on these matters.

13. Following consultation with the Illinois Department of Natural Resources, the Illinois EPA has committed to participate in an interagency monitoring program as needed to address concerns related to overall air quality at the Midewin National Tallgrass Prairie (Midewin), as a result of the proposed plant and other development that may occur near the Midewin.

SECTION 2: IDENTIFICATION OF SIGNIFICANT EMISSIONS UNITS

Unit Number	Description	Emission Control Measures
1	Boiler 1 - Circulating Fluidized Bed Boiler	Good Combustion Practices, Limestone Addition to the Bed, Selective Non-Catalytic Reduction, Trimming Scrubber and Baghouse
	Boiler 2 - Circulating Fluidized Bed Boiler (Identical to Boiler 1)	Good Combustion Practices, Limestone Addition to the Bed, Selective Non-Catalytic Reduction, Trimming Scrubber and Baghouse (identical to control for Boiler 1)
2	Bulk Material Handling Operations	Baghouses and Dust Control Measures
3	Cooling Towers	High-Efficiency Drift Eliminators
4	Auxiliary Boiler - Natural Gas Fired Boiler	Low-NO_x Burners
5	Roadways and Other Sources of Fugitive Dust	Paving and Dust Control Measures

SECTION 3: SOURCE-WIDE CONDITIONS

SOURCE-WIDE CONDITION 1: EFFECT OF PERMIT

a. This permit does not relieve the Permittee of the responsibility to comply with all local, state and federal regulations that are part of the applicable Illinois State Implementation Plan, as well as all other applicable federal, state and local requirements.

b. In particular, this permit does not relieve the Permittee from the responsibility to carry out practices during the construction and operation of the plant, such as application of water or dust suppressant sprays to unpaved traffic areas, to minimize fugitive dust and prevent an air pollution nuisance from fugitive dust, as prohibited by 35 IAC 201.141.

SOURCE-WIDE CONDITION 2: VALIDITY OF PERMIT AND COMMENCEMENT OF CONSTRUCTION

a. This permit shall become invalid as applied to the plant and each CFB boiler at the plant if construction is not commenced within 18 months after this permit becomes effective, if construction of a boiler is discontinued for a period of 18 months or more, or if construction of a boiler is not completed within a reasonable period of time, pursuant to 40 CFR 52.21(r)(2) and 40 CFR 63.43(g)(4). This condition supersedes Standard Condition 1.

b. For purposes of the above provisions, the definitions of "construction" and "commence" at 40 CFR 52.21 (b)(8) and (9) shall apply, which requires that a source must enter into a binding agreement for on-site construction or begin actual on-site construction. (See also the definition of "begin actual construction," 40 CFR 52.21 (b)(11)).

SOURCE-WIDE CONDITION 3: EMISSION OFFSETS

a. The Permittee shall maintain 140.4 tons of VOM emission reduction credits generated by other sources in the Chicago ozone nonattainment area such that the total is greater than 1.3 times the VOM emissions allowed from this project.

b. These VOM emission reduction credits are provided by permanent emission reductions as follows. These emission reductions have been relied upon by the Illinois EPA to issue this permit and cannot be used as emission reduction credits for other purposes.

Minnesota Mining and Manufacturing (3M), Bedford Park, I.D. No. 031012AAR
Shutdown of Coating Line 6H: 140.4 tons/year

This reduction has been made federally enforceable by the withdrawal of the air pollution control permits for Coating Line 6H. Accordingly 3M, must obtain a construction permit if it intends to resume operation of the line in the greater Chicago area, in which permit the Illinois EPA will establish restrictions to assure that the line's actual VOM emissions are permanently reduced by at least 140.4 tons/year.

c. Documentation shall be submitted to the Illinois EPA as follows confirming that the Permittee has obtained the requisite amount of VOM emission offsets as specified above:

i. 3M must submit a letter or other document signed by a responsible official or other authorized agent certifying that a transfer of emission reduction credits from Line 6H at its Bedford Park plant has been made to the Permittee in the requisite amount to provide offsets for this proposed plant.

ii. The Permittee must submit a letter or other document signed by a corporate officer or other authorized agent certifying that a transfer of emission reduction credits has been received from 3M in the requisite amount to provide offsets for this proposed plant. In this letter, the Permittee must also acknowledge that it may subsequently transfer these offsets to another party or return them to 3M only if the preparation for or actual construction of the proposed plant is terminated and this permit expires or is withdrawn, as the Permittee is otherwise under a legal obligation to maintain these offsets pursuant to 35 IAC 203.602.

iii. The above material must be submitted to the Illinois EPA no later than six months after the date that this permit becomes effective.

d. The Permittee may obtain emission reduction credits from an alternate source located in the Chicago ozone nonattainment area, other than 3M, if the following requirements are met:

i. Any proposal for an alternate source of emission reduction credits must be received by the Illinois EPA for review not later three months of the date this permit becomes effective and be accompanied by detailed documentation to support the amount and creditability of the proposed credits.

ii. The alternate source(s) of emission reduction credits must be subject to appropriate measures given the nature of the underlying emission reduction to make the reduction permanent and federally enforceable.

iii. The use of emission reduction credits from the alternate source(s) must be approved by the Illinois EPA. In conjunction with any such approval, the Illinois EPA may and shall revise this permit so that Condition 3(b) appropriately identifies the source(s) of credits.

iv. The Permittee and the alternate source(s) of emission reduction credits must submit to the Illinois EPA, no later than six months after the date that this permit becomes effective, documentation similar in content to that specified by Condition 3(c) to show that transfer of credits has been completed.

e. The Permittee shall not begin actual construction of the proposed plant until applicable requirements with respect to emission offsets, as specified in Condition 3(b) or (c) above, have been satisfied.

Note: This condition represents the actions identified in conjunction with this project to ensure that the project is accompanied by emission offsets and does not interfere with reasonable further progress in reducing VOM emissions in the Chicago ozone nonattainment area. Emission offsets are being required for this project because USEPA has not approved provisions of the Emissions Reduction Market System (ERMS) 35 IAC Part 205, that would allow compliance with the ERMS to satisfy the emission offset requirements in 35 IAC Part 203.

SOURCE-WIDE CONDITION 4: GENERAL PROVISIONS FOR A MAJOR HAP SOURCE

As the plant is a new major source of hazardous air pollutants (HAP) for purposes of Section 112(g) of the Clean Air Act, the Permittee shall comply with all applicable requirements contained in 40 CFR Part 63, Subpart A, pursuant to 40 CFR 63.43(g)(2)(iv).

In particular, for the various emission units at the source, the Permittee shall comply with the following applicable requirements of 40 CFR Part 63 Subpart A, related to startup, shutdown, and malfunction, as defined at 40 CFR 63.2:

a. i. The Permittee shall at all times, including periods of startup, shutdown, and malfunction as defined at 40 CFR 63.2, operate and maintain emission units at the source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions to the levels required by the relevant standards, i.e., meet the emission standard(s) or comply with the applicable Startup, Shutdown, and Malfunction Plan (Plan), as required below. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Illinois EPA and USEPA, which may include, but is not limited to, monitoring results, review of operation and maintenance procedures (including the Plan), review of operation and maintenance records, and inspection of the unit. [40 CFR 63(e)(1)(i)]

ii. The Permittee shall correct malfunctions as soon as practicable after their occurrence in accordance with the applicable Plan. To the extent that an unexpected event arises during a startup, shutdown, or malfunction, the Permittee shall comply by minimizing emissions during such a startup, shutdown, and malfunction event consistent with safety and good air pollution control practices. [40 CFR 63.6(e)(1)(ii)]

iii. These operation and maintenance requirements, which are established pursuant to Section 112 of the Clean Air Act, are enforceable independent of applicable emissions limitations and other applicable requirements. [40 CFR 63(e)(1)(iii)]

b. The Permittee shall develop, implement, and maintain written Startup, Shutdown, and Malfunction Plans (Plans) that describe, in detail, procedures for operating and maintaining the various emission units at the plant during periods of startup, shutdown, and malfunction and a program of corrective action for malfunctioning process, and air pollution control and monitoring equipment used to comply with the relevant emission standards. These Plans shall be developed to satisfy the purposes set forth in 40 CFR 63.6(e)(3)(i)(A), (B) and (C). The Permittee shall develop its initial plans prior to the initial startup of an emission unit(s). [40 CFR 63.6(e)(3)(i)]

i. During periods of startup, shutdown, and malfunction of an emission unit, the Permittee shall operate and maintain such unit, including associated air pollution control and monitoring equipment, in accordance with the procedures specified in the applicable Plan required above. [40CFR 63.6(e)(3)(ii)]

ii. When actions taken by the Permittee during a startup, shutdown, or malfunction (including actions taken to correct a malfunction) are consistent with the procedures specified in the applicable Plan, the Permittee shall keep records for that event which demonstrate that the procedures specified in the Plan were followed. In addition, the Permittee shall keep records of these events as specified in 40 CFR 63.10(b), including records of the occurrence and duration of each startup, shutdown, or malfunction of operation and each malfunction of the air pollution control and monitoring equipment. Furthermore, the Permittee shall confirm in the periodic compliance report that actions taken during periods of startup, shutdown, and malfunction were consistent with the applicable Plan, as required by 40 CFR 63.10(d)(5). [40 CFR 63.6(e)(3)(iii)]

iii. If an action taken by the Permittee during a startup, shutdown, or malfunction (including an action taken to correct a malfunction) of an emission unit is not consistent with the procedures specified in the applicable Plan, and the emission unit exceeds a relevant emission standard, then the Permittee must record the actions taken for that event and must promptly report such actions as specified by 40 CFR 63.63.10(d)(5), unless otherwise specified elsewhere in this permit or in the CAAPP Permit for the plant. [40 CFR 63.6(e)(3)(iv)]

iv. The Permittee shall make changes to the Plan for an emission unit if required by the Illinois EPA or USEPA, as provided for by 40 CFR 63.6(3)(3)(vii), or as otherwise required by 40 CFR 63.6(3)(viii). [40 CFR 63.6(3)(3)(vii) and (viii)]

v. These Plans are records required by this permit, which the Permittee must retain in accordance with the general requirements for retention and availability of records (General Permit Condition 4). In addition, when the Permittee revises a Plan, the Permittee must also retain and make available the previous (i.e., superseded) version of the Plan for a period of at least 5 years after such revision. [40 CFR 63.6(3)(v) and 40 CFR 63.10(b)(1)]

SOURCE-WIDE CONDITION 5: ANCILLARY EQUIPMENT, INCLUDING DIESEL ENGINES

a. Ancillary equipment, including diesel engines, shall be operated in accordance with good air pollution control practice to minimize emissions.

b. i. Diesel engines shall be used to meet the internal electricity or power needs of the plant.

ii. The power output of each diesel engine shall be no more than 1500 horsepower, if it is an emergency or standby unit as defined by 35 IAC 211.1920, or otherwise no more than 500 horsepower.

iii. Fuel fired in diesel engines shall contain no more than 0.05 percent by weight sulfur, so as to qualify as very low sulfur fuel as addressed by the federal Acid Rain program.

SOURCE-WIDE CONDITION 6: AUTHORIZATION TO OPERATE EMISSION UNITS

a. i. Under this permit, each CFB boiler and associated equipment may be operated for a period that ends 180 days after the boiler first generates electricity to allow for equipment shakedown and required emissions testing. This period may be extended by Illinois EPA upon request of the Permittee if additional time is needed to complete shakedown or perform emission testing. This condition supersedes Standard Condition 6.

ii. Upon successful completion of emission testing of a CFB bed boiler demonstrating compliance with applicable limitations, the Permittee may continue to operate the boiler and associated equipment as allowed by Section 39.5(5) of the Environmental Protection Act.

b. i. The remainder of the plant, excluding the CFB boilers, may be operated under this construction permit for a period of 365 days after initial startup of a CFB boiler. This period of time may be extended by the Illinois EPA for up to an additional 365 days upon written request by the Permittee as needed to reasonably accommodate unforeseen difficulties experienced during shakedown of the plant. This condition supersedes Standard Condition 6.

ii. Upon successful completion of emission testing of a CFB boiler demonstrating compliance with applicable limitations, the Permittee may continue to operate the remainder of the plant as allowed by Section 39.5(5) of the Environmental Protection Act.

c. For the CFB boilers and other emission units that are subject to NSPS, the Permittee shall fulfill applicable notification requirements of the NSPS, 40 CFR 60.7(a), including:

i. Written notification of commencement of construction, no later than 30 days after such date (40 CFR 60.7(a)(1)); and

ii. Written notification of the actual date of initial startup, within 15 days after such date (40 CFR 60.7(a)(3)).

SOURCE-WIDE CONDITION 7: AMBIENT ASSESSMENT AND MONITORING

a. The Permittee shall compile information on soil conditions (pH, nutrient levels, trace element content, buffering capacity, etc.) and the condition of vegetation (impact of air pollution and health as indicated by features, rate of growth, etc.) in the Midewin National Tallgrass Prairie (Midewin) as would potentially be affected by pollutants emitted by the proposed plant, as follows:

i. The Permittee shall complete this activity in accordance with a plan that has been submitted to the Illinois Department of Natural Resources (IDNR), the Midewin, and the Illinois EPA for review. As further field data must be collected, the Permittee may contract with qualified experts to collect such data with appropriate oversight by IDNR and the Midewin or work with IDNR and the Midewin to collect such data.

ii. The plan shall be prepared following detailed consultation with IDNR, the Midewin and the Illinois EPA. As part of this consultation with IDNR and the Midewin, the Permittee shall review the existing data available for the area and ongoing data collection efforts. The Permittee shall also solicit recommendations on the scope of further study, including species that should be addressed either as they are threatened or endangered or as they are appropriate indicator species to generally assess the condition of particular ecosystems, the adequacy of the existing data that has been collected in the area for these species, locations for additional sampling sites, the procedures and schedule to be used to collect further data, and the manner in which such data should be collected.

iii. If necessary access to the Midewin can be readily obtained, information shall be compiled for at least ten sites in the vicinity of the plant representing the various ecosystems that are present and four sites in distant locations in the Midewin. These sites shall be selected so as to allow continued collection of representative data at the sites during the operation of the plant.

iv. The compilation of baseline information, representative of the conditions prior to startup of the plant, shall be completed and a comprehensive report submitted prior to the startup of the plant. A subsequent report containing information collected following the startup of the plant shall be prepared and submitted at the same time that the report for optimization of NOx controls required by Unit-Specific Condition 1.16 is required to be submitted. This report shall also include information on the actual operating levels and emissions of the plant during the period over which the soil and vegetation information was collected. Copies of these reports shall be submitted to the IDNR, Midewin, and Illinois EPA

b. The Permittee shall support any monitoring program conducted by the Illinois EPA (or jointly by the Illinois EPA and other governmental bodies) for air emissions impacts in the Midewin, as follows:

   i. Providing the Illinois EPA with any changes in the schedule for construction and startup of the plant, so as to allow baseline monitoring to be conducted for at least a 12-month period prior to initial startup of the plant.

   ii. Assisting in the planning for such monitoring, by reviewing draft monitoring plans, participating in planning meetings and providing comments, as requested.

   iii. Supporting such monitoring, by assisting in identifying suitable sites at which ambient monitoring stations could be located and encouraging the property owners to allow monitoring to be conducted at such sites.

SOURCE-WIDE CONDITION 8: RISK MANAGEMENT PLAN (RMP)

Should this source be subject to the Chemical Accident Prevention Provisions in 40 CFR Part 68, then the Permittee shall submit:

a. A compliance schedule for meeting the requirements of 40 CFR Part 68 by the date provided in 40 CFR 68.10(a); or

b. A certification statement that the source is in compliance with all applicable requirements of 40 CFR Part 68, including the registration and submission of the Risk Management Plan (RMP).

   Note: This condition is imposed pursuant to 40 CFR 68.215(a).

SOURCE-WIDE CONDITION 9: CAPACITY OF PLANT

This permit allows the construction of a power plant that has less capacity than that addressed by the application without obtaining prior approval by the Illinois EPA, as follows. This condition does not affect the Permittee's obligation to comply with the applicable requirements for the various emission units at the plant:

a. The reduction in the capacity of the plant shall generally act to reduce air quality impacts, as emissions from individual emission units are reduced, heights of structures are reduced, but heights of stacks are not significantly affected.

b. The reduction in the capacity of the plant shall result in a pro-rata reduction in the emission limitations established by this permit for the CFB boilers that are based on the capacity of the boilers.

c. The Permittee shall notify the Illinois EPA prior to proceeding with any significant reduction in the capacity of the plant. In this notification, the Permittee shall describe the proposed change and explain why the proposed change will act to reduce impacts, with detailed supporting documentation.

d. Upon written request by the Illinois EPA, the Permittee shall promptly have dispersion modeling performed to demonstrate that the overall effect of the reduced capacity of the plant is to reduce air quality impacts, so that impacts from the plant remain at or below those predicted by the air quality analysis accompanying the application.

SECTION 4: UNIT-SPECIFIC CONDITIONS FOR PARTICULAR EMISSION UNITS

UNIT-SPECIFIC CONDITION 1: CONDITIONS FOR THE CFB BOILERS

1.1 Emission Unit Description

The affected units for the purpose of these specific permit conditions are two circulating fluidized bed (CFB) boilers with individual air pollution control trains. The boilers are designed to use coal mixed with up to 20 percent petroleum coke and waste coal as their primary fuel. The boilers also have the capability to burn natural gas, which is used for startup of the boilers.

1.2 Control Technology Determination

a. Each boiler shall be operated and maintained with the following features to control emissions.

   i. Good combustion practices.

   ii. Limestone addition to the bed.

   iii. Selective noncatalytic reduction (SNCR).

   iv. Trimming scrubber (dry lime scrubber).

   v. Fabric filter or "baghouse".

b. The emissions from each boiler shall not exceed the following limits except during startup, shutdown and malfunction as addressed by Condition 1.2(e). During the shakedown period provided by Source-Wide Condition 5, a boiler is not subject to the SO_2 reduction requirement below and need only comply with the reduction requirement of the NSPS, 40 CFR Part 60, Subpart Da.

   i. PM - 0.015 lb/million Btu.

   This limit shall apply as a 3-hour block average, with compliance determined by emission testing in accordance with Condition 1.8 and equipment operation.

   ii. SO_2 - 0.15 lb/million Btu and, if emissions are 0.10 lb/million Btu or greater, 8 percent of the potential combustion concentration (92 percent reduction) of the solid fuel supply, as received.

   These limits shall apply on a 30 day rolling average with compliance determined using the compliance procedures set forth in the NSPS, 40 CFR 60.48a.

   iii. NO_x - 0.10 lb/million Btu, or such lower limit as set by the Illinois EPA following the Permittee's evaluation of NO_x emissions and the SNCR system in accordance with Conditions 1.15. For this purpose, the demonstration period for the boiler shall be the first two years of operation.

   This limit shall apply on a 30-day rolling average using the compliance procedures of the NSPS, 40 CFR Part 60.48a.

iv. CO - 0.11 lb/million Btu or 321.4 lb/hr*.

This limit shall apply on a 24-hour block average basis, with continuous monitoring conducted in accordance with Condition 1.8.

v. VOM - 0.004 lb/million Btu or 11.7 lb/hr*.

This limit shall apply as a 3-hour block average, with compliance determined by emission testing in accordance with Condition 1.8 and equipment operation.

* This alternative standard is the product of the standard in lb/million Btu and the rated heat input capacity of the boiler.

c. i. The boilers shall each comply with one of the following requirements with respect to emissions of mercury:

A. An emission rate of 0.000002 lb/million Btu or emissions below the detection level of established test methodology (Option A);

B. A removal efficiency of 95 percent achieved without injection of activated carbon or other similar material specifically used to control emissions of mercury, comparing the emissions and the mercury contained in the fuel supply (Option B);

C. Injection of powdered activated carbon or other similar material specifically used to control emissions of mercury in a manner that is designed to achieve the maximum practicable degree of mercury removal (Option C);

D. The requirements for control of mercury emissions established by USEPA pursuant to Section 112(d) of the Clean Air Act (Option D), if such regulations are adopted by USEPA prior to commencement of construction of the affected boiler or if the standard established by such regulations for mercury emissions would be more stringent than one of the above standards. In such case, the Permittee shall promptly notify the Illinois EPA that it intends to comply with the applicable requirements of the adopted regulations and explain the basis on which such election is made.

ii. A. Compliance with Option A or B shall be demonstrated by periodic testing and proper operation of an affected boiler consistent with other applicable requirements that relate to control of mercury (e.g., requirements applicable to particulate matter and SO_2 emissions) as may be further developed or revised in the source's CAAPP Permit. Compliance with Option C shall be demonstrated by proper operation of a boiler and such other measures specified by the applicable construction permit for the injection system.

B. Options A, B and C shall take effect 18 months after initial startup of an affected boiler, provided however, the Permittee may, upon written notice to the Illinois EPA, extend this period for up to an additional 12 months if needed for detailed evaluation of mercury emissions from the boilers or physical changes to the boilers related to control of mercury emissions.

As part of this notice, the Permittee shall explain why the necessary evaluation of emissions or physical changes to the boilers could not reasonably be completed earlier, identify the activities that it intends to perform to evaluate emissions or further enhance control for emissions, and specify the particular practices it will use during this period as good air pollution control practice to minimize emissions of mercury. Prior to the date that Option A, B and C are in effect, the Permittee shall use good air pollution control practices to minimize emissions of mercury.

d. i. The boilers shall each comply with one of the following requirements with respect to emissions of hydrogen chloride:

A. An emission rate of 0.01 lb/million or such lower limit, as low as 0.006 lb/million Btu, as set by the Illinois EPA following the Permittee's evaluation of hydrogen chloride emissions and the acid gas control system, which evaluation shall be submitted with the application for CAAPP permit for the source. This evaluation shall be performed in a manner similar to the evaluation of NO_x emissions required by Condition 1.15. Upon submission of the evaluation and until such time as the Illinois EPA completes its review of the evaluation, a boiler shall comply with the emission limit proposed in the evaluation. (Option A);

B. A removal efficiency of 98 percent, comparing the emissions and the chlorine content of the fuel supply, expressed as equivalent hydrogen chloride (Option B);

C. The requirements for control of hydrogen chloride emissions established by USEPA pursuant to Section 112(d) of the Clean Air Act, once applicable regulations are adopted by USEPA (Option C), if such regulations are adopted by USEPA prior to commencement of construction of the affected boiler or if the standard established by such regulations for hydrogen chloride emissions would be more stringent than one of the above standards. In such case, the Permittee shall promptly notify the Illinois EPA that it intends to comply with the applicable requirements of the adopted regulations and explain the basis on which such election is made.

ii. A. Compliance with Option A and B shall be demonstrated by periodic testing and proper operation of a boiler consistent with other applicable requirements that relate to control of SO_2 emissions, as may be further developed or revised in the source's CAAPP Permit.

B. Option A and B shall take effect 12 months after initial startup of a boiler. Prior to such date, the Permittee shall use good air pollution control practices to minimize emissions of hydrogen chloride.

e. The Permittee shall use reasonable practices to minimize emissions during startup, shutdown and malfunction of a boiler as further addressed in Condition 1.6, including the following:

i. Use of natural gas, during startup to heat the boiler prior to initiating firing of solid fuel;

ii. Operation of the boiler and associated air pollution control equipment in accordance with written operating procedures that include startup, shutdown and malfunction plan(s); and

iii. Inspection, maintenance and repair of the boiler and associated air pollution control equipment in accordance with written maintenance procedures.

1.3 Applicable Federal Emission Standards

a. i. The boilers are subject to a New Source Performance Standard (NSPS) for Electric Utility Steam Generating Units, 40 CFR 60, Subparts A and Da. The Illinois EPA administers NSPS in Illinois on behalf of the USEPA under a delegation agreement.

ii. The emissions from each boiler shall not exceed the applicable limits pursuant to the NSPS. In particular, the NO_x emissions from each boiler shall not exceed 1.6 lb/MW-hr gross energy output, based on a 30-day rolling average, pursuant to 40 CFR 60.44a(d).

iii. The particulate matter emissions from each boiler shall not exceed 20 percent opacity (6-minute average), except for one 6- minute period per hour of not more than 27 percent opacity pursuant to 40 CFR 60.42a(b).

b. At all times, the Permittee shall maintain and operate each boiler, including associated air pollution control equipment, in a manner consistent with good air pollution control practice for minimizing emissions, pursuant to 40 CFR 60.11(d).

1.4 Applicable State Emission Standards

Each boiler is subject to the following state emission standards.

a. Opacity - 35 IAC 212.122 (20 percent opacity, except as allowed by 35 IAC 212.122(b))*

b. Particulate Matter - 35 IAC 212.201 (0.1 lb/million Btu)**

c. Sulfur Dioxide - 35 IAC 214.121 (1.2 lb/million Btu)**

d. Carbon Monoxide - 35 IAC 216.121 (200 ppm, @ 50 % excess air)**

e. Nitrogen Oxides - 35 IAC 217.121 (0.7 lb/million Btu)**

* This standard is not as stringent as Condition 1.3(a)(iii).

** This standard is not as stringent as Condition 1.2.

1.5. Applicability of Other Regulations

a. Each boiler is an affected unit under the federal Acid Rain Deposition Control Program pursuant to Title IV of the Clean Air Act and is subject to certain control requirements and emissions monitoring requirements pursuant to 40 CFR Parts 72, 73 and 75. (See also Trading Program Condition 1, (Section 5, Condition 1).

b. The boilers would qualify as Electrical Generating Units (EGU) for purposes of 35 IAC Part 217, Subpart W, the NO_x Trading Program for Electrical Generating Units. As EGU, the Permittee would have to hold NO_x allowances for the NO_x emissions of the boilers during each seasonal control period. (See also Trading Program Condition 3 (Section 5, Condition 3).

c. For particulate matter, the boilers are pollutant-specific emissions units that will be subject to 40 CFR Part 64, Compliance Assurance Monitoring for Major Stationary Sources. As such, the application for Clean Air Act Permit Program (CAAPP) Permit for the source must include a Compliance Assurance Monitoring (CAM) plan for the boilers.

1.6 Operating Requirements

a. The Permittee shall operate each boiler and associated air pollution control equipment in accordance with good air pollution control practice to minimize emissions, by operating in accordance with detailed written operating procedures as it is safe to do so, which procedures at a minimum shall:

i. Address startup, normal operation, and shutdown and malfunction events and provide for review of relevant operating parameters of the boiler systems during startup, shutdown and malfunction as necessary to make adjustments to reduce or eliminate any excess emissions.

ii. With respect to startup, address readily foreseeable startup scenarios, including so called "hot startups" when the operation of a boiler is only temporarily interrupted and provide for appropriate operating review of the operational condition of a boiler prior to initiating startup of the boiler.

iii. With respect to malfunction, identify and address likely malfunction events with specific programs of corrective actions and provide that upon occurrence of a malfunction that will result in emissions in excess of the applicable limits in Condition 1.2, the Permittee shall, as soon as practicable, repair the affected equipment, reduce the operating rate of the boiler or remove the boiler from service so that excess emissions cease.

Consistent with the above, if the Permittee has maintained and operated a boiler and associated air pollution control equipment so that malfunctions are infrequent, sudden, not caused by poor maintenance or careless operation, and in general are not reasonably preventable, the Permittee shall begin shutdown of the boiler within 90 minutes, unless the malfunction is expected to be repaired within 120 minutes or such shutdown could threaten the stability of the regional electrical power supply. In such case, shutdown of the system shall be undertaken when it is apparent that repair will not be accomplished within 120 minutes or shutdown will not endanger the regional power system. In no case shall shutdown of the boiler be delayed solely for the economic benefit of the Permittee.

Note: If the Permittee determines that the continuous emission monitoring system (CEMS) is inaccurately reporting excess emissions, the boiler may continue to operate provided the Permittee records the information it is relying upon to conclude that the boiler and associated emission control systems are functioning properly and the CEMS is reporting inaccurate data and the Permittee takes prompt action to resolve the accuracy of the CEMS.

b. The Permittee shall maintain each boiler and associated air pollution control equipment in accordance with good air pollution control practice to assure proper functioning of equipment and minimize malfunctions, including maintaining the boiler in accordance with written procedures developed for this purpose.

c. The Permittee shall handle the fuel for the boilers in accordance with a written Fuel Management Plan that shall be designed to provide the boilers with a consistent fuel supply that meets relevant criteria needed for proper operation of the boilers and their control systems.

d. The Permittee shall review its operating and maintenance procedures and its fuel management plan for the boilers as required above on a regular basis and revise them if needed consistent with good air pollution control practice based on actual operating experience and equipment performance. This review shall occur at least annually if not otherwise initiated by occurrence of a startup, shakedown, or malfunction event that is not adequately addressed by the existing plans or a specific request by the Illinois EPA for such review.

1.7 Emission Limitations

Emissions from the boilers shall not exceed the limits in Table I. The limits in Table I are based upon the emission rates and the maximum firing rate specified in the permit application consistent with the air quality analysis submitted by the Permittee to comply with PSD. Compliance with hourly limits shall be determined with testing and monitoring as required by Conditions 1.8 and 1.9 and proper equipment operation in accordance with Condition 1.6.

1.8 Emission Testing

a. i. A. Within 60 days after achieving the maximum production rate at which an affected boiler will be operated but not later than 180 days after initial startup of each boiler, the Permittee shall have tests conducted for opacity and emissions of NO_x, CO, PM, VOM, SO_2, hydrogen chloride, hydrogen fluoride, sulfuric acid mist, and mercury and other metals as follows at its expense by an approved testing service while the boiler is operating at maximum operating load and other representative operating conditions, including firing of coal only and coal with supplemental fuel. (In addition, the Permittee may also perform measurements to evaluate emissions at other load and operating conditions.)

B. This period of time may be extended by the Illinois EPA for up to an additional 365 days upon written request by the Permittee as needed to reasonably accommodate unforeseen difficulties in the startup and testing of the boiler, provided that initial performance testing required by the NSPS, 40 CFR Part 60, Subpart Da has been completed for the boiler and the test report submitted to the Illinois EPA.

ii. Between 9 and 15 months after performance of the initial testing that demonstrates compliance with applicable requirements, the Permittee shall have the emissions of PM, VOM, hydrogen chloride, hydrogen fluoride, sulfuric acid mist, and mercury and other metals from each affected boiler retested as specified above.

iii. A. Thereafter, the Permittee shall have PM emissions from each affected boiler tested at a regular interval. This interval shall be no greater than 36 months, unless the results of two consecutive PM tests for a boiler demonstrate PM emissions of 0.010 lb/million Btu or less, in which case the interval between tests shall be no greater than 72 months. However, if a PM test for a boiler then shows PM emissions above 0.010 lb/million Btu, the maximum interval between testing shall revert to 36 months until two consecutive tests again show PM emissions of 0.010 lb/million Btu or less. For the purposes of these provisions, the two consecutive tests must be at least 24 months apart.

B. Whenever PM testing for a boiler is performed as required above, testing for emissions of mercury and hydrogen chloride shall also be performed as provided below.

iv. In addition to the emission testing required above, the Permittee shall have emission tests conducted as requested by the Illinois EPA for a boiler within 45 days of a written request by the Illinois EPA or such later date agreed to by the Illinois EPA. Among other reasons, such testing may be required if there is a significant increase in the mercury or chlorine content of the fuel supply to the boilers.

Note: Specific requirements for periodic emission testing may be established in the CAAPP Permit for the plant.

v. Within two years of the initial startup of each affected boiler, the Permittee shall have emission testing conducted for dioxin/furan emissions.

b. The following methods and procedures shall be used for testing, unless otherwise specified or approved by the Illinois EPA.

Location of Sample Points	Method 1
Gas Flow and Velocity	Method 2
Flue Gas Weight	Method 3 or 3A
Moisture	Method 4
Particulate Matter[1]	Method 5, as specified by 40 CFR 60.48a(b), and Method 201 or 201A (40 CFR 51, Appendix M)
Condensable Particulate	Method 202
Opacity[2]	Method 9, as specified by 40 CFR 60.48a(b)(3)
Nitrogen Oxides[2]	Method 19, as specified by 40 CFR 60.48a(d)
Sulfur Dioxides[2]	Method 19, as specified by 40 CFR 60.48a(c)
Carbon Monoxide[2]	Method 10
Volatile Organic Material[3]	Method 18 or 25A
Sulfuric Acid Mist	Method 8
Hydrogen Chloride	Method 26
Hydrogen Fluoride	Method 26
Metals [4, 5]	Method 29
Dioxin/Furan	Method 23

Notes:

1. The Permittee may report all PM emissions measured by USEPA Method 5 as PM_{10}, in which case separate testing using USEPA Method 201 or 201A need not be performed.

2. Emission testing shall be conducted for purposes of certification of the continuous emission monitors required by Condition 1.9. Thereafter, the NO_x, SO_2 and CO emission data from certified monitors may be provided in lieu of conducting emissions tests.

3. The Permittee may exclude methane, ethane and other exempt compounds from the results of any VOM test provided that the test protocol to quantify and correct for any such compounds is included in the test plan approved by the Illinois EPA.

4. For purposes of this permit, metals are defined as mercury, arsenic, beryllium, cadmium, chromium, lead, manganese, and nickel.

5. During the initial emissions testing for metals, the Permittee shall also conduct measurements using established test methods for the principle forms of mercury present in the emissions, i.e., particle bound mercury, oxidized mercury and elemental mercury.

c. i. Test plans, test notifications, and test reports shall be submitted to the Illinois EPA in accordance with the General Condition 2 (Section 6, Conditions 2)

ii. In addition to other information required in a test report, test reports shall include detailed information on the operating conditions of a boiler during testing, including:

A. Fuel consumption (in tons);

B. Composition of fuel (Refer to Condition 1.10(b)), including the metals, chlorine and fluorine content, expressed in pound per million Btu;

C. Firing rate (million Btu/hr) and other significant operating parameters of the boiler, including temperature in the boiler in the area before the SNCR system;

D. Control device operating rates, e.g., limestone addition rate, SNCR reagent injection rate, injection rate of trimming scrubber, baghouse pressure drop, etc.;

E. Opacity of the exhaust from the boiler, 6-minute averages and 1-hour averages;

F. Turbine/Generator output rate (MWe).

1.9 Emission Monitoring

a. i. The Permittee shall install, certify, operate, calibrate, and maintain continuous monitoring systems on each boiler for opacity, emissions of SO_2, NO_x and CO, and either oxygen or carbon dioxide in the exhaust.

ii. The Permittee shall fulfill the applicable requirements for monitoring in the NSPS (40 CFR 60.13, 60.47a, and 40 CFR 60 Appendix B), the federal Acid Rain Program (40 CFR Part 75), the NO_x Trading Program for Electrical Generating Units (35 IAC Part 217, Subpart W) and NESHAP (40 CFR 63.8 and 63.10). These rules require that the Permittee maintain detailed records for both the measurements made by these systems and the maintenance, calibration and operational activity associated with the monitoring systems.

iii. The Permittee shall also operate and maintain these monitoring systems according to site-specific monitoring plan(s), which shall be submitted at least 60 days before the initial startup of a boiler to the Illinois EPA for its review and approval. With this submission, the Permittee shall submit the proposed type of monitoring equipment and proposed sampling location(s), which shall be approved by the Illinois EPA prior to installation of equipment.

b. In addition, when NO_x or SO_2 emission data are not obtained from a continuous monitoring system because of system breakdowns, repairs, calibration checks and zero span adjustments, emission data shall be obtained by using standby monitoring systems, emission testing using USEPA Reference Methods (Method 7 or 7A for NO_x and Method 6 for SO_2), or other approved methods as necessary to provide emission data for a minimum of 75 percent of the operating hours in a boiler operating day, in at least 22 out of 30 successive boiler operating days, pursuant to 40 CFR 60.47a(f) and (h).

Note: Fulfillment of the above criteria for availability of emission data from a monitoring system does not shield the Permittee from potential enforcement for failure to properly maintain and operate the system.

1.10. Operational Monitoring and Measurements

a. The Permittee shall install, evaluate, operate, and maintain meters to measure and record consumption of natural gas by each boiler.

b. i. A. The Permittee shall sample and analyze the sulfur and heat content of the fuel supplied to the boilers in accordance with USEPA Reference Method 19 (40 CFR 60, Appendix A, Method 19).

B. This sampling and analysis shall include separate measurements for the sulfur and heat content of the fuels supplied to the boilers.

ii. The Permittee shall analyze samples of all coal supplies and any alternate fuel supplies that are components in the solid fuel supply to the boilers and the solid fuel supply itself for mercury and other metals, chlorine and fluorine content, as follows:

A. Analysis shall be conducted in accordance with USEPA Reference Methods or other method approved by USEPA.

B. Analysis of the fuel supply to the boiler itself shall be conducted in conjunction with performance testing of a boiler.

C. Analysis of representative samples of solid fuels shall be conducted in conjunction with acceptance of fuel from a new coal mine or an alternate fuel.

D. Analysis of representative samples of solid fuels shall be conducted at least every two years, if a more frequent analysis is not needed pursuant to the above requirements.

E. The CAAPP permit may revise or relax these requirements.

c. i. The Permittee shall install, operate and maintain systems to measure key operating parameters of the control equipment and control measures for each boiler, including:

A. Limestone addition rate to the bed;

B. Temperature in the boiler in the area before the SNCR system;

C. Reagent injection rate for the SNCR unit;

D. Sorbent injection rate for the trimming scrubber;

E. Pressure drop across the baghouse.

ii. The Permittee shall maintain the records of the measurements made by these systems and records of maintenance and operational activity associated with the systems.

d. If a Performance Specification for particulate matter continuous monitoring systems is adopted by USEPA more than 6 months before the scheduled date for initial start-up of the first boiler, the Permittee shall install and operate such a system on each boiler for the purpose of compliance assurance monitoring. The Permittee shall operate, calibrate and maintain each such system in accordance with the applicable USEPA performance specification and other applicable requirements of the NSPS for monitoring systems and in a manner that is generally consistent with published USEPA guidance for use such systems for compliance assurance monitoring, e.g., *Fabric Filter Bag Leak Detection Guidance*, EPA-454/R-98-015, September 1997. The Permittee shall also operate and maintain these monitoring systems according to a site-specific monitoring plan, which shall be submitted at least 60 days before the initial startup of a boiler to the Illinois EPA for its review and approval. With this submission, the Permittee shall submit the proposed type of monitoring equipment and proposed sampling location, which shall be approved by the Illinois EPA prior to installation of equipment.

1.11. Recordkeeping

a. The Permittee shall maintain the following records with respect to operation and maintenance of each boiler and associated control equipment:

i. An operating log for the boiler that at a minimum shall address:

A. Each startup of the boiler, including the nature of the startup, sequence and timing of major steps in the startup, any unusual occurrences during the startup, and any deviations from the established startup procedures, with explanation;

B. Each shutdown of the boiler including the nature and reason for the shutdown, sequence and timing of major steps in the shutdown, any unusual occurrences during the shutdown, and any deviations from the established shutdown procedures, with explanation; and

C. Each malfunction of the boiler system that significantly impairs emission performance, including the nature and duration of the event, sequence and timing of major steps in the malfunction, corrective actions taken, any deviations from the established procedures for such a malfunction, and preventative actions taken to address similar events.

ii. Inspection, maintenance and repair log(s) for the boiler system that at a minimum shall identify such activities that are performed as related to components that may effect emissions; the reason for such activities, i.e., whether planned or initiated due to a specific event or condition, and any failure to carry out the established maintenance procedures, with explanation.

iii. Copies of the steam charts and daily records of steam and electricity generation.

b. The Permittee shall maintain records of the following items related to fuels used in the boilers:

i. Records of the sampling and analysis of solid fuel supply to the boilers conducted in accordance with Condition 1.10(b).

ii. A. The sulfur content of solid fuel, lb sulfur/million Btu, supplied to each boiler, as determined pursuant to Condition 1.10(b)(i); and

B. The sulfur content of solid fuel supplied to the boiler on a 30-day rolling average, determined from the above data.

iii. The amount of fuel combusted in each boiler by type of fuel as specified in 40 CFR Part 60, Appendix A, Method 19.

c. For each boiler, the Permittee shall maintain records of the following items related to emissions:

i. Records of SO_2 NO_x and PM emissions and operation for each boiler operating day, as specified by 40 CFR 60.49a.

ii. With respect to the SO_2 reduction based limit in Condition 1.2(b)(ii) and 1.3, for each 30 day averaging period, the SO_2 emissions in lb/million Btu and the required SO_2 emission rate as determined by applying the permissible emission fraction to the potential SO_2 emission rate of the solid fuel supply.

iii. Records of CO emissions of the boiler based on the continuous emissions monitoring system required by Condition 1.9.

iv. Records of emissions of VOM, mercury and other pollutants from the boiler, based on fuel usage and other operating data for the boiler and appropriate emission factors, with supporting documentation.

d. The Permittee shall record the following information for any period during which a boiler deviated from applicable requirements:

i. Each period when the operating parameters of the baghouse, such as pressure drop, as measured pursuant to Condition 1.10, deviated outside the levels set as good air pollution control practice (date, duration and description of the event).

ii. Each period when a baghouse failed to operate properly, which records shall include at least the information specified by General Condition 3 (Section 6, Condition 3).

iii. Each period during which an affected unit exceeded the requirements of this permit, including applicable emission limits, which records shall include at least the information specified by General Condition 3 (Section 6, Condition 3).

1.12. Notifications

a. The Permittee shall notify the Illinois EPA within 30 days of deviations from applicable requirements that are not addressed by the regular reporting required below. These notifications shall include the information specified by General Condition 4 (Section 6, Condition 4).

b. The Permittee shall notify the Illinois EPA in writing at least 30 days prior to initial firing of any solid fuel other than coal, petroleum coke or coal tailings in a boiler.

1.13. Reporting

a. i. The Permittee shall fulfill applicable reporting requirements in the NSPS, 40 CFR 60.7(c) and 60.49a, for each boiler. For this purpose, quarterly reports shall be submitted no later than 30 days after the end of each calendar quarter. (40 CFR 60.49a (i))

ii. In lieu of submittal of paper reports, the Permittee may submit electronic quarterly reports for SO_2, NO_x or opacity. The electronic reports shall be submitted no later than 30 days after the end of the calendar quarter and shall be accompanied by a certification statement indicating whether compliance with applicable emission standards and minimum data requirements of 40 CFR 60.49a were achieved during the reporting period. (40 CFR 60.49a(j))

b. i. Either as part of the periodic NSPS report or accompanying such report, the Permittee shall report to the Illinois EPA any and all opacity and emission measurements for a boiler that are in excess of the respective requirements set by this permit. These reports shall provide for each such incident, the pollutant emission rate, the date and duration of the incident, and whether it occurred during startup, malfunction, breakdown, or shutdown. If an incident occurred during malfunction or breakdown, the corrective actions and actions taken to prevent or minimize future reoccurrences shall also be reported.

ii. These reports shall also address any deviations from applicable compliance procedures for a boiler established by this permit, including specifying periods during which the continuous monitoring systems were not in operation.

c. The Permittee shall comply with applicable reporting requirements under the Acid Rain Program, with a single copy of such report sent to Illinois EPA, Bureau of Air, Compliance and Enforcement Section.

1.14 Operational Flexibility/Anticipated Operating Scenarios

a. The Permittee is authorized to use fuel from different suppliers in the boilers without prior notification to the Illinois EPA or revision of this permit.

b. This condition does not affect the Permittee's obligation to continue to comply with applicable requirements or to properly obtain a construction permit in a timely manner for any activity involving the boiler or the fuel handling equipment that constitutes construction or modification of an emission unit, as defined in 35 IAC 201.102.

1.15 Optimization of Control of NO_x Emissions

a. i. The Permittee shall evaluate NO_x emissions from boilers to determine whether a lower NO_x emission limit (as low as 0.08 lb/million Btu) may be reliably achieved while complying with other emission limits and without significant risk to equipment or personnel. This evaluation shall also examine whether there will be significant increase in ammonia-related emissions from the boilers, as well as unreasonable increase in maintenance and repair needed for the boilers.

ii. This permit will be revised to set lower emission limit(s) for NO_x emissions (but no lower than 0.08 lb/million Btu) if as a result of this evaluation the Illinois EPA finds that the boilers can consistently comply with such limit(s). Additional parameters or factors, e.g., the nitrogen content of the fuel supply, may be included in such limits to address particular modes of operation during which particular emission limits may or may not be achievable.

iii. If the Permittee fails to complete the evaluation or submit the required report in a timely manner, the NO_x emission limit shall automatically revert to 0.08 lb NO_x per million Btu

b. The Permittee shall perform this evaluation of NO_x emissions in accordance with a plan submitted to the Illinois EPA for review and comment. The initial plan shall be submitted to the Illinois EPA no later than 90 days after initial start-up of a boiler..

c. The plan shall provide for systematic evaluation of changes, within the normal or feasible range of operation, in the following elements as related to the monitored NO_x emissions:

i. Boiler operating load and operating settings;

ii. Operating rate and settings of the SNCR system;

iii. Flue gas temperature at SNCR injection point(s);

iv. Combustion settings, including excess oxygen;

v. Limestone and sorbent usage rates;

vi. Nitrogen content of the fuel supply;

vii. Particulate matter and operating parameters for baghouses;

viii. Opacity, particulate matter and sulfuric acid mist emissions; and

ix. Ammonia slip (emissions of ammonia and secondary ammonia compounds).

d. The Permittee shall promptly begin this evaluation after a boiler demonstrates compliance with the applicable emission limits as shown by emission testing and monitoring. At this time, the Permittee shall submit an update to the plan that describes its findings with respect to control of NO_x emissions during the shakedown of the boilers, which highlights possible areas of concern for the evaluation.

e. i. This evaluation shall be completed and a detailed written report submitted to the Illinois EPA within two years after the initial startup of a boiler. This report shall include proposed alternative limit(s) for NO_x emissions.

ii. This deadline may be extended for an additional year if the Permittee submits an interim report demonstrating the need for additional time to effectively evaluate NO_x emissions or to coordinate this evaluation with the ambient assessment required by Source-Wide Condition 7.

1.16 Construction of Additional Control Measures

The Permittee is generally authorized under this permit to construct and operate additional devices and features to control emissions from a boiler, which are not described in the application for this permit, as follows. This condition does not affect the Permittee's obligation to comply with the applicable requirements for the boilers:

a. This authorization only extends to devices or features that are designed to reduce emissions, such as the addition of adsorbent materials other than limestone to the boiler bed and ductwork injection of sorbent materials other than lime or wet scrubbing prior to the baghouse. These measures may also serve to improve boiler operation as they reduce consumption of materials but do not include measures that would increase a boiler's rated heat input capacity.

b. This authorization only extends to additional devices or features that are identified during the detailed design of the boilers and any refinements to that design that occur during construction and the initial operation of the boilers.

c. Prior to beginning actual construction of any new control device, the Permittee shall apply for and obtain a separate construction permit for it from the Illinois EPA pursuant to 35 IAC Part 201, Subpart D. In the application for this permit, the Permittee shall describe the additional device and explain how it will act to reduce emissions, with detailed supporting documentation. In acting upon this permit, the Illinois EPA may specify additional operating parameters that must be monitored or measured, such as pressure drop across the scrubber, and additional provisions for required emissions testing.

d. Upon written request by the Illinois EPA, the Permittee shall promptly have dispersion modeling performed to demonstrate that the proposed device or feature for which a construction permit would be required does not significantly effect the air quality impacts from the boilers, so that impacts from the boilers are of the same magnitude of those predicted by the air quality analysis accompanying the application.

UNIT-SPECIFIC CONDITION 2: CONDITIONS FOR BULK MATERIAL HANDLING OPERATIONS

2.1 Description of Emission Units

The affected units for the purpose of these unit-specific permit conditions are operations that handle materials in bulk that are involved with the operation of the power plant and have the potential for particulate matter emissions, including coal, petroleum coke, coal tailings, limestone, and ash. Affected units include receiving, transfer, handling, storage, processing or preparation (drying, crushing, etc.) and loading operations for such materials.

2.2 Control Technology Determination

a. i. Emissions of particulate matter from affected units, other than operations associated with material storage in building or associated with storage piles, shall be controlled with enclosures and aspiration to baghouses or other filtration devices designed to emit no more than 0.005 grains/dry standard cubic foot (gr/dscf). These devices shall be operated in accordance with good air pollution control practice to minimize emissions.

ii. There shall be no visible fugitive emissions, as defined by 40 CFR 60.671, from storage buildings.

iii. Storage piles shall be controlled by enclosure, material quality, temporary covers and application of water or other dust suppressants so as to minimize fugitive emissions to the extent practicable.

b. i. The only fuel burned in the limestone drying mills shall be natural gas, as defined by 40 CFR 60.41a.

ii. Emissions from each limestone drying mill attributable to combustion of fuel shall not exceed the following limits, except during startup and shutdown. These limits shall apply as a 3-hour block average, with compliance determined in accordance with Condition 2.8 and proper operation.

A. NO_x - 0.073 lb/million Btu.

B. CO - 0.20 lb/million Btu.

C. VOM - 0.02 lb/million Btu.

2.3 Applicable Federal Emission Standards

a. Affected units engaged in handling limestone shall comply with applicable requirements of the NSPS for Nonmetallic Mineral Processing Plants, 40 CFR 60, Subpart OOO and related provisions of 40 CFR 60, Subpart A.

i. Pursuant to the NSPS, stack emissions of particulate matter are subject to the following limitations:

A. The rate of emissions shall not exceed 0.05 gram/dscm (0.02 g/dscf) (40 CFR 60.672(a)(1))*

B. The opacity of emissions shall not exceed 7 percent. (40 CFR 60.672(a)(2))

ii. Pursuant to the NSPS, fugitive emissions of particulate matter are subject to the following limitations:

A. The opacity of emissions from grinding mills, screens (except truck dumping), storage bins, and enclosed truck or railcar loading operations shall not exceed 10 percent. (40 CFR 60.672(b) and (d))*

B. The opacity of emissions from crushers shall not exceed 10 percent. (40 CFR 60.672(c))*

C. Truck dumping into any screening operation, feed hopper, or crusher is exempt from the above standards. (40 CFR 60.672(d))*

b. Affected units engaged in handling coal shall comply with applicable requirements of the NSPS for Coal Preparation Plants, 40 CFR 60, Subpart Y, and related provisions of 40 CFR 60, Subpart A. Note: These NSPS are applicable because coal will be processed at the plant by crushing.

Pursuant to the NSPS, the opacity of the exhaust from coal processing and conveying equipment, coal storage systems (other than open storage piles), and coal loading systems shall not exceed 20 percent.*

* Condition 2.2(a) establishes a more stringent requirement than this standard.

c. At all times, the Permittee shall maintain and operate affected units that are subject to NSPS, including associated air pollution control equipment, in a manner consistent with good air pollution control practice for minimizing emissions, pursuant to 40 CFR 60.11(d).

d. This permit reflects a determination by the Illinois EPA that the NSPS for Calciners and Dryers in Mineral Industries, 40 CFR 60 Subpart UUU, does not apply to the limestone drying systems because processing of limestone is not addressed by these standards.

2.4 Applicable State Emission Standards

a. The emission of smoke or other particulate matter from affected units shall not have an opacity greater than 30 percent, except as allowed by 35 IAC 212.124. Compliance with this limit shall be determined by 6-minute averages of opacity measurements in accordance with USEPA Reference Method 9. [35 IAC 212.109 and 212.123(a)]

b. With respect to emissions of fugitive particulate matter, affected units shall comply with 35 IAC 212.301, which provides that visible emissions of fugitive particulate matter shall not be visible from any process, including any material handling or storage activity, when looking generally toward the zenith at a point beyond the property line of the source, except as provided by 35 IAC 212.314.

c. Affected units shall comply with applicable emission standards for fugitive particulate matter, as follow, which generally apply to the source because it is located in Channahon Township, Will County.

i. Crushers, grinding mills, screening operations, conveyor transfer points, conveyors, bagging operations, storage bins, and fine product truck and railcar loading operations shall be sprayed with water or a surfactant solution, utilize choke-feeding, or be treated by an equivalent method of emission control [35 IAC 212.308]

ii. All unloading and transportation of materials collected by pollution control equipment shall be enclosed or shall utilize spraying, pelletizing, screw conveying or other equivalent methods [35 IAC 212.307].

2.5 Applicability of Other Regulations

a. This permit is issued based on the outdoor storage piles at the plant not meeting the applicability thresholds of 35 IAC 212.304, so that the provisions of 35 IAC 212.304, 212.305, and 212.306 are not applicable.

b. This permit is issued based on affected units readily complying with the applicable particulate matter emission limit pursuant to 35 IAC 212.321, which rule limits emissions based on the process weight rate of an unit and allows a minimum emission rate emission of 0.55 lb/hour for any unit.

2.6 Operating Requirements

a. i. The plant shall be designed and operated to store bulk materials that have the potential for particulate matter emissions in silos, bins, and buildings, without storage of such material in outdoor piles except on a temporary basis during breakdown or other disruption in the capabilities of the enclosed storage facilities.

ii. The plant shall be designed and operated with enclosed conveyors for transfer of coal and limestone from the material storage facility to the boiler facility, and these materials shall only be transferred by truck on a temporary basis during breakdown of the conveyor system.

b. i. The Permittee shall carry out control of fugitive particulate matter emissions from affected units in accordance with a written operating program describing the measures being implemented in accordance with Conditions 2.2 and 2.4 to control emissions at each area of the plant with the potential to generate significant quantities of such emissions, which program shall be kept current.

A. This program shall include maps or diagrams indicating the location of affected units with the potential for fugitive emissions, accompanied the following information for each such unit: a general description of the unit, its size (area or volume), the expected level of activity, the nature and extent of enclosure, and a description of installed air pollution control equipment.

B. This program shall include a detailed description of any additional emission control technique (e.g., water or surfactant spray) including: typical flow of water and additive concentration; rate or normal frequency at which measures would be implemented; circumstances in which the measure would not be implemented e.g., adequate surface moisture on material; triggers for additional control, e.g. observation of 10 percent opacity; and calculated control efficiency.

C. This program shall also meet any further requirements of 35 IAC 212.309 and 212.310 for affected units subject to 35 IAC 212.307 or 212.308 (Condition 2.4).

ii. The Permittee shall submit copies of this operating program to the Illinois EPA for review as follows:

A. A program for the construction of the plant shall be submitted with 30 days of beginning actual construction of the plant.

B. The initial operating program for plant shall be submitted within 90 days of initial start up of the plant.

C. Significant amendments to the program by the Permittee shall be submitted within 30 days.

iii. A revised operating program shall be submitted to the Illinois EPA for review within 90 days of a request from the Illinois EPA for revision to address observed deficiencies in control of fugitive emissions.

c. The Permittee shall conduct inspections of affected units on at least a monthly basis to verify that the measures identified in the operating program and other measures required to control emissions from affected units are being properly implemented. When the plant begins to handle bulk materials in the affected units, these inspections shall include observation of buildings and structures in which affected units are located for the occurrence of visible emissions.

d. i. This permit does not authorize operation of the affected units for purposes that are unrelated to the operation of the power plant, such as receiving and storing coal that is then shipped to another source.

ii. A. The only fuel used for affected units shall be natural gas.

B. The rated heat input capacity of affected units shall not exceed 36 million Btu/hour, total.

2.7 Emission Limitations

Emissions from affected units shall not exceed the limitations in Table II and III and the limitations specified in the records required by Condition 2.11(a).

2.8 Emission Testing

a. i. A. Within 60 days after achieving the maximum production rate at which a limestone drying mill or other affected emission unit subject to NSPS will be operated but not later than 180 days after initial startup of each such unit, the Permittee shall have emissions tests conducted as follows for such unit below by an approved testing service at its expense under conditions that are representative of maximum emissions.

B. This period of time may be extended by the Illinois EPA upon written request by the Permittee as needed to reasonably accommodate unforeseen difficulties in the startup and testing of an affected unit, provided that initial emissions testing required by the NSPS has been completed for the unit and the test report submitted to the Illinois EPA.

ii. In addition to the initial emission testing required above, the Permittee shall perform emission tests as requested by the Illinois EPA for an affected unit within 45 days of a written request by the Illinois EPA or such later date agreed to by the Illinois EPA.

b. The following methods and procedures shall be used for emission testing

i. The following USEPA methods and procedures shall be used for particulate matter and opacity measurements for the affected units subject to 40 CFR Part 60, Subpart OOO, as specified in 40 CFR 60.675:

Particulate Matter	Method 5 or 17
Opacity	Method 9

ii. The following USEPA methods and procedures shall be used for particulate matter and opacity measurements for the affected units subject to 40 CFR 60, Subpart Y, as specified in 40 CFR 60.254:

Particulate Matter - Method 5, the sampling time and sample volume for each run shall be at least 60 minutes and 30 dscf. Sampling shall begin no less than 30 minutes after startup and shall terminate before shutdown procedures begin.

Opacity - Method 9, opacity measurements shall be performed by a certified observer.

iii. The following USEPA methods and procedures shall be used for testing the combustion emissions of one randomly selected limestone mill:

Nitrogen Oxides	Method 19
Carbon Monoxide	Method 10
Volatile Organic Material	Method ~~18 or~~ 25A and 18

c. Test plan(s), test notifications, and test reports shall be submitted to the Illinois EPA in accordance with General Condition 2. (Section 6, Condition 2)

2.9 Emission Monitoring

None

2.10 Operational Monitoring and Measurements

a. The Permittee shall install, operate and maintain systems to measure the pressure drop across the baghouse associated with each limestone mill.

b. The Permittee shall maintain the records of the measurements made by these systems and records of maintenance and operational activity associated with the systems.

2.11 Recordkeeping

a. The Permittee shall maintain files, which shall be kept current, that contain:

i. A. For the baghouses or other filter devices associated with affected units, design specifications for the device (type of device, maximum design exhaust flow (acfm or scfm), filter area, type of filter cleaning, performance guarantee for particulate exhaust loading in gr/scf, etc.), the manufacturer's recommended operating and maintenance procedures for the device, and design specification for the filter material in each device (type of material, surface treatment(s) applied to material, weight, performance guarantee, warranty provisions, etc.).

B. In addition, for each baghouse associated with a limestone mill, the normal range of pressure drop across the device and the minimum and maximum safe pressure drop for the device, with supporting documentation.

ii. For the burners in the affected limestone drying mills, the manufacturer's rated heat input and guarantees or design data for emissions of NOx, CO and VOM.

iii. The designated particulate matter emission rate, in pounds/hour, from each stack or vent associated with the affected units, other than those units individually addressed by Table III. For each category of affected unit (e.g., receiving and handling), the sum of these emission rates and the hourly limitations for any units that are addressed individually shall not exceed the hourly subtotal in Table III for the category of affected unit. (See also Condition 2.

b. i. The Permittee shall keep records for the amount of each bulk material received by or shipped from the plant (tons/month).

ii. The Permittee shall keep records for any incident in bulk materials were deposited outside of a building, with detailed explanation and a description of the practices used to minimize emissions.

c. For affected units that are subject to NSPS, the Permittee shall fulfill applicable recordkeeping requirements of the NSPS, 40 CFR 60.676

d. The Permittee shall keep inspection and maintenance logs for each control device associated with an affected unit.

e. The Permittee shall maintain records documenting implementation of the fugitive emission operating program required by Condition 2.6, including:

i. Records for inspections to verify the implementation of continuous control measures (that are to be in place whenever an affected unit is in operation), including the date and time, the name of the responsible party, identification of the affected unit(s) that were inspected, and the observed condition of control measures;

ii. Records for the implementation of intermittent control measures, i.e., application of suppressants including identification of the affected unit, identification of the suppressant, application rate, dates or date and time of applications, and quantity of total suppressant applied;

iii. Records for application of physical or chemical control agents other than water including the name of the agent; target application concentration, if diluted with water; target application rate; and usage of the agent, gallons/month; and

iv. A log recording incidents when control measures were not present or were not used for an affected unit when it was in operation, including description, date, duration, and a statement of explanation.

f. The Permittee shall record any period during which an affected unit was in operation when its baghouse was not in operation or was not operating properly, as follows:

i. Each period when the pressure drop of a baghouse for a limestone drying system, as measured pursuant to Condition 2.9, deviated outside the levels set as good air pollution control practice (date, duration and description of the event).

ii. Each period when a baghouse failed to operate properly, which records shall include at least the information specified by General Condition 3 (Section 6, Condition 3).

iii. Each period during which an affected unit deviated from the requirements of this permit, including applicable emission limits, which records shall include at least the information specified by General Condition 3 (Section 6, Condition 3).

g. The Permittee shall keep records for all opacity observations made in accordance with USEPA Method 9 for affected units that it conducts or that are conducted on its behalf by individuals who are certified to make such observations. For each occasion on which such observations are made, these records shall include the identity of the observer, a description of the various observations that were made, the observed opacity from individual units, and copies of the raw data sheets for the observations.

h. The Permittee shall maintain the following records for the emissions of the affected units:

i. Records of emissions of particulate matter based on operating data for the unit(s) and appropriate emission factors, with supporting documentation.

ii. Records of emissions of emissions of NO_x, CO and VOM from affected units drying limestone based on fuel usage, operating data and appropriate emission factors, with supporting documentation.

2.12 Notifications

The Permittee shall notify the Illinois EPA within 30 days of deviations from applicable emission standards or operating requirements that continue* for more than 24 hours. These notifications shall include the information specified by General Condition 5 (Section 6, Condition 5).

* For this purpose, time shall be measured from the start of a particular event. The absence of a deviation for a short period shall not be considered to end the event if the deviation resumes. In such circumstances, the event shall be considered to continue until corrective actions are taken so that the deviation ceases or the Permittee takes the affected unit out of service for repairs.

2.13 Reporting

a. The Permittee shall submit quarterly reports to the Illinois EPA for all deviations from emission standards, including standards for visible emissions and opacity, and operating requirements set by this permit for affected units. These notifications shall include the information specified by General Condition 5 (Section 6, Condition 5)

b. These reports shall also address any deviations from applicable compliance procedures established by this permit for affected units.

2.14 Operating Flexibility

The Permittee is authorized to construct and operate affected units that are different from those described in the application as follows without obtaining prior approval by the Illinois EPA. This condition does not affect the Permittee's obligation to comply with the applicable requirements for affected units:

a. This authorization only extends to changes that result from the detailed design of the plant and any refinements to that design that occur during construction and the initial operation of the plant.

b. With respect to air quality impacts, these changes shall generally act to improve dispersion and reduce impacts, as emissions from individual units are lowered, units are moved apart or away from the fence line, stack heights are increased, and heights of nearby structures is reduced.

c. The Permittee shall notify the Illinois EPA prior to proceeding with any changes. In this notification, the Permittee shall describe the proposed changes and explain why the proposed changes will act to reduce impacts, with detailed supporting documentation.

d. Upon written request by the Illinois EPA, the Permittee shall promptly have dispersion modeling performed to demonstrate that the overall effect of the changes is to reduce air quality impacts, so that impacts from affected units remain at or below those predicted by the air quality analysis accompanying the application.

UNIT-SPECIFIC CONDITION 3: CONDITIONS FOR COOLING TOWERS

3.1 Description of Emission Units

The affected units for the purpose of these unit-specific conditions are two mechanical draft wet cooling towers associated with the steam cycle for each CFB boiler. The cooling towers are sources of particulate matter because of mineral material present in the water, which is emitted to the atmosphere due to water droplets that escape from the cooling tower or completely evaporate. The emissions of particulate matter are controlled by drift eliminators at the top of the towers, which collect water droplets entrained in the air exhausted from the cooling towers.

3.2 Control Technology Determination

The affected units shall be equipped, operated, and maintained with drift eliminators designed to limit the loss of water droplets from the unit to not more than 0.0005 percent of the circulating water flow.

3.2 Applicable Federal Emission Standards

None

3.4 Applicable State Emission Standards

Visible emission of fugitive particulate matter from the affected units shall comply with the provisions of 35 IAC 212.301, which provides that visible emissions of fugitive particulate matter shall not be visible from any process, including any material handling or storage activity, when looking generally toward the zenith at a point beyond the property line of the source, except as provided by 35 IAC 212.314.

3.5 Applicability of Other Regulations

None

3.6 Operating Requirements

a. Chromium-based water treatment chemicals, as defined in 40 CFR 63.401, shall not be used in the affected units.

b. i. A. The Permittee shall equip the affected units with appropriate features, such as steam reheat, to enable them to be operated without a significant contribution to fogging and icing on offsite roadways during periods when fogging or icing are present in the area or weather conditions are conducive to fogging or icing.

B. Notwithstanding the above, the Permittee need not include such features in the affected units if it demonstrates by appropriate analysis, as approved in writing by the Illinois EPA, that the cooling towers will be sited and designed and can be operated such that additional features are not needed to prevent a significant contribution to fogging and icing on offsite roadways.

ii. No later than 30 days after completion of the detailed design of the affected units and at least 60 days before construction of the affected units is begun, the Permittee shall submit a summary of the detailed design to the Illinois EPA and either:

A. A detailed description of the physical features that will be included in the affected units to satisfy Condition 3.6(b)(i)(A), the practices that would be followed for such features, and a demonstration that such features will be sufficient to prevent a significant contribution to fogging and icing on offsite roadways, for review and comment by the Illinois EPA; or

B. An analysis pursuant to Condition 3.6(b)(i)(B), including any operational practices that would be followed for the affected units to prevent a significant contribution to fogging and icing on offsite roadways, for review and approval by the Illinois EPA.

c. The Permittee shall operate and maintain the affected units, including the drift eliminators, in a manner consistent with good air pollution control practice for minimizing emissions.

d. The Permittee shall operate and maintain the affected units in accordance with written operating procedures, which procedures shall be kept current. These procedures shall address the practices that will be followed as good air pollution control practice and the actions that will be followed to prevent a significant contribution to icing and fogging on offsite roadways.

3.7 Emission Limitations

The total annual emissions of particulate matter from the affected units shall not exceed 8.4 tons/year, as determined by appropriate engineering calculations.

3.8 Emission Testing

None

3.9 Emission Monitoring

None

3.10 Operational Monitoring and Measurements

a. The Permittee shall measure the total dissolved solids content in the water being circulated in the affected units on at least a monthly basis. Measurements of the total dissolved solids content in the wastewater discharge associated with the affected units, as required by a National Pollution Discharge Elimination System permit, may be used to satisfy this requirement if the effluent has not been diluted or otherwise treated in a manner that would significantly reduce its total dissolved solids content.

b. Upon written request by the Illinois EPA, the Permittee shall promptly have the water circulating in the affected units sampled and analyzed for the presence of hexavalent chromium in accordance with the procedures of 40 CFR 63.404(a) and (b).

3.11 Records

a. The Permittee shall keep a file that contains:

i. The design loss specification for the drift eliminators installed in each affected unit.

ii. The suppliers recommended procedures for inspection and maintenance of the drift eliminators.

iii. The operating factors, if any, used to determine the amount of water circulated in the affected units or the particulate matter emissions from the affected units, with supporting documentation.

iv. Copies of the Material Safety Data Sheets or other comparable information from the suppliers for the various water treatment chemicals that are added to the water circulated in the affected units.

b. The Permittee shall keep the following operating records for the affected units:

i. The amount of water circulated in the affected units, gallons/month. As an alternative to direct data for water flow, these records may contain other relevant operating data for the units (e.g., water flow to the units) from which the amount of water circulated in the units may be reasonably determined.

ii. Each occasion when the Permittee took action to prevent a significant contribution to fogging or icing from the affected units, including the date and duration, the action or actions that were taken, the weather conditions that triggered such actions, and the weather conditions when actions were terminated.

c. The Permittee shall keep inspection and maintenance logs for the drift eliminators installed in each affected unit.

d. The Permittee shall maintain records for the particulate matter emissions of the affected units based on the above records, the measurements required by Condition 3.10(a), and appropriate USEPA emission estimation methodology and emission factors, with supporting calculations.

3.12 Notifications

The Permittee shall notify the Illinois EPA within 30 days of deviations from applicable requirements for an affected unit. These notifications shall include the information specified by General Condition 4 (Section 6, Condition 4).

UNIT-SPECIFIC CONDITION 4: CONDITIONS FOR THE AUXILIARY BOILER

4.1 Description of Emission Unit

The affected unit for the purpose of these unit-specific conditions is the auxiliary boiler for the plant, which is fired with natural gas. The auxiliary boiler is used to produce low-pressure steam to maintain the plant when the coal-fired boilers are not in operation and support the startup of the coal-fired boilers.

4.2 List of Emission Units and Pollution Control Equipment

Emission Unit	Description	Emission Control Equipment
Boiler	Natural Gas-Fired Boiler, with Rated Heat Input Capacity of no More Than 99 Million Btu/Hr	Low-NO_x Burner

4.2 Control Technology Determination

a. The only fuel burned in the affected boiler shall be natural gas.

b. The emissions from the boiler shall not exceed the following limits except during startup, shutdown and malfunction as addressed by Condition 1.2(c).

i. NO_x - 0.08 lb/million Btu.

This limit shall apply as a 3-hour block average, with compliance determined by emission testing in accordance with Condition 4.8 and proper operation.

ii. CO - 0.1 lb/million Btu.

This limit shall apply as a 3-hour block average, with compliance determined by emission testing in accordance with Condition 4.8 and proper operation.

iii. VOM - 0.02 lb/million.

This limit shall apply as a 3-hour block average, with compliance determined by emission testing in accordance with Condition 4.8 and proper operation.

c. The Permittee shall use reasonable practices to minimize emissions during startup, shutdown and malfunction of the affected boiler, including:

i. Operation of the boiler and associated air pollution control equipment in accordance with written operating procedures that include startup, shutdown and malfunction plan(s); and

ii. Inspection, maintenance and repair of the boiler and associated air pollution control equipment in accordance with written maintenance procedures.

4.3 Applicable Federal Emission Standards

a. The affected boiler is subject to a New Source Performance Standard (NSPS) for Small Industrial-Commercial-Institutional Steam Generating Units, 40 CFR 60, Subpart Dc, and related provisions in Subpart A.

b. At all times, the Permittee shall maintain and operate the affected boiler, including associated air pollution control equipment, in a manner consistent with good air pollution control practice for minimizing emissions, pursuant to 40 CFR 60.11(d).

c. This permit reflects a determination by the Illinois EPA that the affected boiler is not subject to emission standards under the NSPS because the boiler does not burn oil or solid fuel.

4.4 Applicable State Emission Standards

a. The emission of smoke or other particulate matter from the affected boiler shall not have an opacity greater than 30 percent, except as allowed by 35 IAC 212.124. Compliance with this limit shall be determined by 6-minute averages of opacity measurements in accordance with USEPA Reference Method 9. [35 IAC 212.109 and 212.123(a)]

b. The emission of carbon monoxide (CO) into the atmosphere from the affected boiler shall not exceed 200 ppm, corrected to 50 percent excess air. [35 IAC 216.121]

4.5 Applicability of Regulations of Concern

This permit is issued on the affected boiler not being an electrical generating unit, so that provisions of the federal Acid Rain Program are not applicable to the boiler.

4.6 Operating Requirements

a. The affected boiler shall only be fired with natural gas.

b. The rated heat input of the affected boiler shall not exceed 99 million Btu/hour.

c. The affected boiler shall not operate for more than 2500 hours per year when a CFB boiler is in operation. Compliance with this limit shall be determined from a running total of 12 months of data.

4.7 Emission Limitations

Emissions of NO_x, VOM, CO, PM and SO2 from the affected boiler shall not exceed 9.9, 2.5, 12.4, 1.2 and 0.7 tons/year, respectively. Compliance with these annual limits shall be determined on a monthly basis from the sum of the data for the current month plus the preceding 11 months.

4.8 Emission Testing

a. i. Within 60 days after achieving the maximum production rate at which the affected boiler will be operated but not later than 180 days after initial startup of the boiler, the Permittee shall have tests conducted for opacity and emissions of NO_x, CO and VOC as follows at its expense by an approved testing service while the boiler is operating at maximum operating load and other representative operating conditions.

ii. In addition to the emission testing required above, the Permittee shall perform emission tests as requested by the Illinois EPA for the affected boiler within 45 days of a written request by the Illinois EPA or such later date agreed to by the Illinois EPA.

b. The following methods and procedures shall be used for testing, unless otherwise specified or approved by the Illinois EPA.

Opacity	Method 9
Location of Sample Points	Method 1
Gas Flow and Velocity	Method 2
Flue Gas Weight	Method 3 or 3A
Moisture	Method 4
Nitrogen Oxides[1]	Method 7, 7E or 19 as specified in 40 CFR 60.48b
Carbon Monoxide	Method 10
Volatile Organic Compounds	Method 25A and 18

c. Test plans, test notifications, and test reports shall be submitted to the Illinois EPA in accordance with the General Condition 2 (Section 6, Conditions 2)

4.9 Operational Monitoring and Measurements

None

4.10 Emission Monitoring

None

4.11 Recordkeeping

a. The Permittee shall keep a file that contains:

i. The rated heat input capacity of the affected boiler as provided by the manufacturer or subsequently determined based on the demonstrated heat input capacity of the boiler.

b. The Permittee shall maintain the following operating records for the affected boiler:

i. An operating log or other record that among other matters identifies each period when the boiler is operated.

ii. A summary of operating hours (hours/month and hours/year) for all operation and for operation when a CFB boiler was operating.

iii. Natural gas usage on a monthly basis (million Btu or cubic feet).

c. The Permittee shall maintain a maintenance and repair log for the affected boiler.

d. The Permittee shall keep records of the annual NO_x, VOM, CO, PM and SO_2 emissions from the affected boiler, based on fuel consumption, operating data, and applicable emission factors, with supporting calculations.

4.12 Notifications

The Permittee shall notify the Illinois EPA within 30 days of deviations from applicable requirements. These notifications shall include the information specified by General Condition 4 (Section 6, Condition 4).

4.13 Reporting

The Permittee shall fulfill applicable reporting requirements of the NSPS, 40 CFR 60.49b, for the affected boiler by sending the following notifications and reports to the Illinois EPA:

a. The Permittee shall submit notification of the date of initial startup of the boiler, as provided by 40 CFR 60.7. This notification shall include: (1) the design heat input of the boiler, and (2) the annual capacity factor at which the Permittee anticipates operating the boiler. [40 CFR 60.49c(a)]

4.14 Operational Flexibility/Anticipated Operating Scenarios

None

4.15 Compliance Procedures

Compliance with the emission limits in Condition 4.7 shall be based on the operating records required by Condition 4.11 and appropriate emission factors.

a. The emission factors for NO_x, CO, and VOM shall be based on the results of the emission testing required by Condition 4.8.

b. The following emission factors may be used for PM and SO_2 when the affected boiler operates properly. These are the emission factors for small natural gas fired boilers from USEPA's *Compilation of Air Pollutant Emission Factors*, AP-42, October 1996.

Pollutant	Emission Factor (lb/million ft^3)
PM	3.0
SO_2	0.6

UNIT-SPECIFIC CONDITION 5: CONDITIONS FOR ROADWAYS AND OTHER OPEN AREAS

5.1 Description of Emission Units

The affected units for the purpose of these unit-specific conditions are roadways, parking areas and open areas at the plant, which may be sources of fugitive particulate matter due to vehicle traffic or wind blown dust.

5.2 Control Technology Determination

a. Good air pollution control practices shall be implemented to minimize and significantly reduce nuisance dust from affected units. After construction of the plant is complete, these practices shall provide for pavement on all regularly traveled roads and treatment (flushing, vacuuming, dust suppressant application, etc.) of paved and unpaved roads and areas that are routinely subject to vehicle traffic for very effective and effective control of dust, respectively (nominal 90 percent for paved roads and areas and 80 percent control for unpaved roads and areas).

b. For this purpose, roads that serve the main office, or are used on a daily basis by operating and maintenance personnel for the plant or by security personnel in the course of their typical duties, or experience heavy use during regularly occurring maintenance of the plant during the course of a year, shall all be considered subject to regular travel and required to be paved. Regularly traveled roads shall be considered to be subject to routine vehicle traffic except as they are used primarily for periodic maintenance and are currently inactive or as traffic has been temporarily blocked off. Other roads shall be considered to be subject to routine travel if activities are occurring such that the roads are experiencing significant vehicle traffic.

5.3 Applicable Federal Emission Standards

None

5.4 Applicable State Emission Standards

a. Affected units shall comply with 35 IAC 212.301, which provides that visible emissions of fugitive particulate matter shall not be visible from any process, including any material handling or storage activity, when looking generally toward the zenith at a point beyond the property line of the source, except as provided by 35 IAC 212.314.

b. The handling of material collected from affected unit by sweeping or vacuuming trucks shall comply with 35 IAC 212.307, which provides that all unloading and transportation of materials collected by pollution control equipment shall be enclosed or shall utilize spraying, pelletizing, screw conveying or other equivalent methods [35 IAC 212.307].

5.5 Applicability of Other Regulations

This permit reflects a determination by the Illinois EPA that the source is a power plant or electrical generating operation so that the provisions of 35 IAC 212.306 are not applicable to roads and parking areas at the source. [35 IAC 212.306]

5.6 Operating Requirements

a. i. The Permittee shall carry out control of fugitive particulate matter emissions from affected units in accordance with a written operating program describing the measures being implemented in accordance with Conditions 5.2 and 5.4 to control emissions at each unit with the potential to generate significant quantities of such emissions, which program shall be kept current.

A. This program shall include maps or diagrams indicating the location of affected units with the potential to generate significant quantities of fugitive particulate matter, with description of the unit (length, width, surface material, etc.), the volume and nature of expected vehicle traffic or other activity on such unit, and an identification of any roadways that are not considered regularly traveled, with justification.

B. This program shall include a detailed description of the emissions control technique (e.g., vacuum truck, water flushing, or sweeping) for the affected unit, including: typical application rate; type and concentration of additives; normal frequency with which measures would be implemented; circumstances, in which the measure would not be implemented, e.g., recent precipitation; triggers for additional control, e.g. observation of 10 percent opacity; and calculated control efficiency for particulate matter emissions.

ii. The Permittee shall submit copies of this operating program to the Illinois EPA for review as follows:

A. A program addressing the construction of the plant shall be submitted within 30 days of beginning actual construction of the plant.

B. A program addressing the operation of the plant shall be submitted within 90 days of initial start up of the plant.

C. Significant amendments to the program by the Permittee shall be submitted within 30 days.

iii. A revised operating program shall be submitted to the Illinois EPA for review within 90 days of a request from the Illinois EPA for revision to address observed deficiencies in control of fugitive particulate emissions.

b. The Permittee shall conduct inspections of affected units on at least a weekly basis during construction of the plant and on a monthly basis thereafter to verify that the measures identified in the operating program and other measures required to control emissions from affected units are being properly implemented.

5.7 Emission Limitations

The total annual emissions of particulate matter from the affected units shall not exceed 5.5 tons/year, as determined by appropriate engineering calculations.

5.8 Emission Testing

None

5.9 Operational Monitoring and Measurements

None

5.10 Emission Monitoring

None

5.11 Records

a. The Permittee shall keep a file that contains:

   i. The operating factors, if any, used to determine the amount of activity associated with the affected units or the particulate matter emissions from the affected units, with supporting documentation.

b. The Permittee shall maintain records documenting implementation of the operating program required by Condition 5.6, including:

   i. For each treatment of an affected unit or units, the name and location of the affected unit(s), the date and time, and the identification of the truck(s) or treatment equipment used;

   ii. For each application of water or chemical solution by truck: application rate of water or suppressant, frequency of each application, width of each application, total quantity of water or chemical used for each application and, for each application of chemical solution, the concentration and identity of the chemical;

   iii. For application of physical or chemical control agents: the name of the agent, application rate and frequency, and total quantity of agent and, if diluted, percent of concentration, used each day; and

   iv. A log recording incidents when control measures were not used and incidents when additional control measures were used due to particular activities, including description, date, a statement of explanation, and expected duration of the such circumstances.

c. The Permittee shall record any period during which an affected unit was not properly controlled as required by this permit, which records shall include at least the information specified by General Condition 3 (Section 6, Condition 3) and an estimate of the additional emissions of particulate matter that resulted, if any, with supporting calculations.

d. The Permittee shall maintain records for the particulate matter emissions of the affected units based on plant operating data, the above records for the affected unit including data for implementation of the operating program, and appropriate USEPA emission estimation methodology and emission factors, with supporting calculations.

5.12 Notifications

The Permittee shall notify the Illinois EPA within 30 days of deviations from applicable requirements for affected units that are not addressed by the regular reporting required below. These notifications shall include the information specified by General Condition 4 (Section 6, Condition 4).

5.13 Reporting

The Permittee shall submit a quarterly report to the Illinois EPA for affected units stating the following: the dates any necessary control measures were not implemented, a listing of those control measures, the reasons that the control measures were not implemented, and any corrective actions taken. This information includes, but is not limited to, those dates when controls were not applied based on a belief that application of such control measures would have been unreasonable given prevailing atmospheric conditions. This report shall be submitted to the Illinois EPA no later than 45 calendar days from the end of each calendar quarter.

SECTION 5: TRADING PROGRAM CONDITIONS

TRADING PROGRAM CONDITION 1: ACID RAIN PROGRAM REQUIREMENTS

a. Applicability

Under Title IV of the Clean Air Act, Acid Deposition Control, this plant or source is an affected source and the following emission units at the source are affected units for acid deposition:

Circulating Fluidized Bed Boilers 1 and 2

Note: Title IV of the Clean Air Act, and other laws and regulations promulgated thereunder, establish requirements for affected sources related to control of emissions of pollutants that contribute to acid rain. For purposes of this permit, these requirements are referred to as Title IV provisions.

b. Applicable Emission Requirements

The owners and operators of the source shall not violate applicable Title IV provisions. In particular, SO_2 emissions of the affected units shall not exceed any allowances that the source lawfully holds under Title IV provisions. [Environmental Protection Act, Sections 39.5(7)(g) and (17)(l)]

Note: Affected sources must hold SO_2 allowances to account for the SO_2 emissions from affected units at the source that are subject to Title IV provisions. Each allowance is a limited authorization to emit up to one ton of SO_2 emissions during or after a specified calendar year. The possession of allowances does not authorize exceedances of applicable emission standards or violations of ambient air quality standards.

c. Monitoring, Recordkeeping and Reporting

The owners and operators of the source and, to the extent applicable, their designated representative, shall comply with applicable requirements for monitoring, recordkeeping and reporting specified by Title IV provisions, including 40 CFR Part 75. [Environmental Protection Act, Sections 39.5(7)(b) and 17(m)]

Note: As already addressed in Unit-Specific Condition 1, the following emission determination methods would be used for the affected units at this source.

NO_x:	Continuous emissions monitoring (40 CFR 75.12)
SO_2:	Continuous emissions monitoring (40 CFR 75.11)
Opacity:	Continuous emission monitoring (40 CFR 75.14)
O_2/CO_2:	Continuous monitoring for oxygen or carbon dioxide (40 CFR 75.13)

d. Acid Rain Permit

The owners and operators of the source shall comply with the terms and conditions of the source's Acid Rain permit. [Environmental Protection Act, Section 39.5(17)(l)]

Note: The source is subject to an Acid Rain permit, which was issued pursuant to Title IV provisions, including Section 39.5(17) of the Act. Affected sources must be operated in compliance with their Acid Rain permits. The initial Acid Rain permit is included as an attachment to this permit. Revisions and modifications of this Acid Rain permit, including administrative amendments and automatic amendments (pursuant to Sections 408(b) and 403(d) of the CAA or regulations thereunder) are governed by Title IV provisions, as provided by Section 39.5(13)(e) of the Environmental Protection Act, and revision or renewal of the Acid Rain permit may be handled separately from this permit.

e. Coordination with Other Requirements

i. This permit does not contain any conditions that are intended to interfere with or modify the requirements of Title IV provisions. In particular, this permit does not restrict the flexibility under Title IV provisions of the owners and operators of this source to amend their Acid Rain compliance plan. [Environmental Protection Act, Section 39.5(17)(h)]

ii. Where another applicable requirement of this permit is more stringent than an applicable requirement of Title IV provisions, both requirements are enforceable and the owners and operators of the source shall comply with both requirements. [Environmental Protection Act, Section 39.5(7)(h)]

TRADING PROGRAM CONDITION 2: EMISSIONS REDUCTION MARKET SYSTEM (ERMS)

a. Description of ERMS

The ERMS is a "cap and trade" market system for major stationary sources located in the Chicago ozone nonattainment area. It is designed to reduce VOM emissions from stationary sources to contribute to reasonable further progress toward attainment, as required by Section 182(c) of the CAA.

The ERMS addresses VOM emissions during a seasonal allotment period from May 1 through September 30. Participating sources must hold "allotment trading units" (ATUs) for their actual seasonal VOM emissions. Each year participating sources are issued ATUs based on allotments set in the sources' CAAPP permits. These allotments are established from historical VOM emissions or "baseline emissions" lowered to provide the emissions reductions from stationary sources required for reasonable further progress.

By December 31 of each year, the end of the reconciliation period following the seasonal allotment period, each source shall have sufficient ATUs in its transaction account to cover its actual VOM emissions during the preceding season. A transaction account's balance as of December 31 will include any valid ATU transfer agreements entered into as of December 31 of the given year, provided such agreements are promptly submitted to the Illinois EPA for entry into the transaction account database. The Illinois EPA will then retire ATUs in sources' transaction accounts in amounts equivalent to their seasonal emissions. When a source does not appear to have sufficient ATUs in its transaction account, the Illinois EPA will issue a notice to the source to begin the process for Emissions Excursion Compensation.

In addition to receiving ATUs pursuant to their allotments, participating sources may also obtain ATUs from the market, including ATUs bought from other participating sources and general participants in the ERMS that hold ATUs (35 IAC 205.630). During the reconciliation period, sources may also buy ATUs from a secondary reserve of ATUs managed by the Illinois EPA, the "Alternative Compliance Market Account" (ACMA) (35 IAC 205.710). Sources may also transfer or sell the ATUs that they hold to other participants (35 IAC 205.630).

b. Applicability

This plant or source is considered a "new participating source" for purposes of the ERMS, 35 IAC Part 205.

c. Obligation to Hold Allotment Trading Units (ATUs)

In accordance with 35 IAC 205.150(d)(1), at the end of the reconciliation period each year, once the source commences operation, the source shall hold ATUs in an amount not less than 1.3 times its VOM emissions during the preceding seasonal allotment period (May 1 through September 30), determined in accordance with applicable provisions in Section 3 of this permit or the source's CAAPP permit, not including VOM emissions from the following, or the source shall be subject to "emissions excursion compensation," as described in Condition 2(e):

i. VOM emissions from insignificant emission units, if any, as identified in the source's CAAPP permit, in accordance with 35 IAC 205.220;

ii. Excess VOM emissions associated with startup, malfunction, or breakdown of an emission unit as authorized by 35 IAC 201.262, if any, in accordance with 35 IAC 205.225;

iii. Excess VOM emissions that are a consequence of an emergency at the source as approved by the Illinois EPA, in accordance with 35 IAC 205.750; and

iv. Excess VOM emissions to the extent allowed by a Variance, Consent Order, or Compliance Schedule, in accordance with 35 IAC 205.320(e)(3).

d. Market Transactions

i. The source shall apply to the Illinois EPA for and obtain authorization for a Transaction Account prior to conducting any market transactions, as specified at 35 IAC 205.610(a).

ii. The source shall promptly submit to the Illinois EPA any revisions to the information submitted for its Transaction Account, pursuant to 35 IAC 205.610(b).

iii. The source shall have at least one account officer designated for its Transaction Account, pursuant to 35 IAC 205.620(a).

iv. Any transfer of ATUs to or from the source from another source or general participant must be authorized by a qualified Account Officer designated by the source and approved by the Illinois EPA, in accordance with 35 IAC 205.620, and the transfer must be submitted to the Illinois EPA for entry into the Transaction Account database.

e. Emissions Excursion Compensation

Pursuant to 35 IAC 205.720, if the source fails to hold ATUs in accordance with Condition 2(c), it shall provide emissions excursion compensation in accordance with the following:

i. Upon receipt of an Excursion Compensation Notice issued by the Illinois EPA, the source shall purchase ATUs from the ACMA in the amount specified by the notice, as follows:

A. The purchase of ATUs shall be in an amount equivalent to 1.2 times the emissions excursion; or

B. If the source had an emissions excursion for the seasonal allotment period immediately before the period for the present emissions excursion, the source shall purchase ATUs in an amount equivalent to 1.5 times the emissions excursion.

ii. If requested in accordance with Condition 2(e)(iii) below or in the event that the ACMA balance is not adequate to cover the total emissions excursion amount, the Illinois EPA will deduct ATUs equivalent to the specified amount or any remaining portion thereof from the ATUs issued to the source for the next seasonal allotment period.

iii. Pursuant to 35 IAC 205.720(c), within 15 days after receipt of an Excursion Compensation Notice, the owner or operator may request that ATUs equivalent to the amount specified be deducted from the source's next seasonal allotment by the Illinois EPA, rather than purchased from the ACMA.

f. Quantification of Seasonal VOM Emissions

i. The methods and procedures specified in Sections 4 of this permit (Unit-Specific Conditions) or the CAAPP permit for the source shall be used for determining seasonal VOM emissions for purposes of the ERMS.

ii. The Permittee shall report emergency conditions at the source to the Illinois EPA, in accordance with 35 IAC 205.750, if the Permittee intends to deduct VOM emissions that are in excess of a technology-based VOM emission rate normally achieved and are attributable to the emergency from the source's seasonal VOM emissions for purposes of the ERMS. These reports shall include the information specified by 35 IAC 205.750(a), and shall be submitted in accordance with the following:

A. An initial emergency conditions report within two days after the time when such excess emissions occurred due to the emergency; and

B. A final emergency conditions report, if needed to supplement the initial report, within 10 days after the conclusion of the emergency.

g. Annual Account Reporting

i. For each year in which the source is operational, the Permittee shall submit, as a component of its Annual Emissions Report, seasonal VOM emissions information to the Illinois EPA for the seasonal allotment period. This report shall include the following information [35 IAC 205.300]:

A. Actual seasonal emissions of VOM from the source;

B. A description of the methods and practices used to determine VOM emissions, as required by this permit, including any supporting documentation and calculations;

C. A detailed description of any monitoring methods that differ from the methods specified in this permit, as provided in 35 IAC 205.337;

D. If the source has experienced an emergency, as provided in 35 IAC 205.750, the report shall reference the associated emergency conditions report that has been approved by the Illinois EPA;

ii. This report shall be submitted by October 31 of each year, for the preceding seasonal allotment period.

h. Allotment of ATUs to the Source

i. As a new participating source, the source will not receive allotments of ATUs from the State of Illinois.

ii. A. If the source enters into a multiple season transfer agreement with another participating source or a general participant in the ERMS, ATUs will be issued to the source's Transaction Account by the Illinois EPA annually for the duration of such agreement. These ATUs will be valid for the seasonal allotment period for which they are issued and, if not retired for this period, the next seasonal allotment period.

B. Notwithstanding the above, part or all of the above ATUs will not be issued to the source in circumstances as set forth in 35 IAC Part 205, including:

1. Transfer of ATUs by the source to another participant or the ACMA, in accordance with 35 IAC 205.630;

2. Deduction of ATUs as a consequence of emissions excursion compensation, in accordance with 35 IAC 205.720.

i. Recordkeeping for ERMS

i. The Permittee shall maintain the following records related to actual VOM emissions of the source during the seasonal allotment period:

A. Records of operating data and other information for each individual emission unit or group of related emission units at the source, as specified in Section 4 of this permit and in the source's CAAPP permit, as appropriate, to determine actual VOM emissions during the seasonal allotment period;

B. Records of the VOM emissions, in tons, during the seasonal allotment period, with supporting calculations, for each individual emission unit or group of related emission units at the source, determined in accordance with the procedures specified in Section 4 of this permit and in the source's CAAPP permit; and

C. Total VOM emissions from the source, in tons, during each seasonal allotment period, which shall be compiled by October 31, of each year.

ii. The Permittee shall maintain copies of the following documents as its Compliance Master File for purposes of the ERMS [35 IAC 205.335 and 205.700(a)]:

A. Seasonal component of the Annual Emissions Report;

B. Information on actual VOM emissions, as specified in detail in Section 4 of this permit and in the source's CAAPP permits; and

C. Any transfer agreements for the purchase or sale of ATUs and other documentation associated with the transfer of ATUs.

TRADING PROGRAM CONDITION 3: NO_x TRADING PROGRAM

a. Description of NO_x Trading Program

The NO_x Trading Program is a regional "cap and trade" market system for large sources of NO_x emissions in the eastern United States, including Illinois. It is designed to reduce and maintain NO_x emissions from the emission units covered by the program within a budget to help contribute to attainment and maintenance of the ozone ambient air quality standard in the multi-state region covered by the program, as required by Section 110 of the Clean Air Act. The NO_x Trading Program applies in addition to other applicable requirements for NO_x emissions and in no way relaxes these other requirements.

Electrical generating units (EGU) that are subject to the NO_x Trading Program are referred to as "budget EGU." Sources that have one or more EGU or other units subject to the NO_x Trading Program are referred to as budget sources.

The NO_x Trading Program controls NO_x emissions from budget EGU and other budget units during a seasonal control period from May 1 through September 30 of each year, when weather conditions are conducive to formation of ozone in the ambient air. (In 2004, the first year that the NO_x Trading Program is in effect, the control period will be May 31 through September 30.) By November 30 of each year, the allowance transfer deadline, each budget source must hold "NO_x allowances" for the actual NO_x emissions of its budget units during the preceding control period. The USEPA will then retire NO_x allowances in the source's accounts in amounts equivalent to its seasonal emissions. If a source does not have sufficient allowances in its accounts, USEPA would subtract allowances from the source's future allocation for the next control period and impose other penalties as appropriate. Stringent monitoring procedures developed by USEPA apply to budget units to assure that NO_x emissions are accurately determined.

The number of NO_x allowances available for budget sources is set by the overall budget for NO_x emissions established by USEPA. This budget requires a substantial reduction in NO_x emissions from historical levels as necessary to meet air quality goals. In Illinois, existing budget sources initially receive their allocation or share of the NO_x allowances budgeted for EGU in an amount determined by rule [35 IAC Part 217, Appendix F]. Between 2007 and 2011, the allocation mechanism for existing EGU gradually shifts to one based on the actual utilization of EGU in preceding control periods. New budget EGU, for which limited utilization data may be available, may obtain NO_x allowances from the new source set-aside (NSSA), a portion of the overall budget reserved for new EGU.

In addition to directly receiving or purchasing NO_x allowances as described above, budget sources may transfer NO_x allowances from one of their units to another. They may also purchase allowances in the marketplace from other sources that are willing to sell some of the allowances that they have received. Each budget source must designate an account representative to handle all its allowance transactions. The USEPA, in a central national system, will maintain allowance accounts and record transfer of allowances among accounts.

The ability of sources to transfer allowances will serve to minimize the costs of reducing NO_x emissions from budget units to comply with the overall NO_x budget. In particular, the NO_x emissions of budget units that may be most economically controlled will be targeted by sources for further control of emissions. This will result in a surplus of NO_x allowances from those units that can be transferred to other units at which it is more difficult to control NO_x emissions. Experience with reduction of SO_2 emissions under the federal Acid Rain program has shown that this type of trading program not only achieves regional emission reductions in a more cost-effective manner but also results in greater overall reductions than application of traditional emission standards to individual emission units.

The USEPA developed the plan for the NO_x Trading Program with assistance from affected states. Illinois' rules for the NO_x Trading Program for EGU are located in 35 IAC Part 217, Subpart W and have been approved by the USEPA. These rules provide for interstate trading, as mandated by Section 9.9 of the Act. Accordingly, these rules refer to and rely upon federal rules at 40 CFR Part 96, which have been developed by USEPA for certain aspects of the NO_x Trading Program, and which an individual state must follow to allow for interstate trading of NO_x allowances.

Note: This narrative description of the NO_x Trading Program is for informational purposes only and is not enforceable.

b. Applicability

The following emission units at this source are budget EGU for purposes of the NO_x Trading Program. Accordingly, this source is a budget source and the Permittee is the owner or operator of a budget source and budget EGU. In this condition, these emission units are addressed as budget EGU.

Boiler 1
Boiler 2

c. General Provisions of the NO_x Trading Program

i. This source and the budget EGU at this source shall comply with all applicable requirements of Illinois' NO_x Trading Program, i.e., 35 IAC Part 217, Subpart W, and 40 CFR Part 96 (excluding 40 CFR 96.4(b) and 96.55(c), and excluding 40 CFR 96, Subparts C, E and I), pursuant to 35 IAC 217.756(a) and 217.756(f)(2).

ii. Any provision of the NO_x Trading Program that applies to a budget source (including any provision applicable to the account representative of a budget source) shall also apply to the owner or operator of such budget sources and to the owner and operator of each budget EGU at the source, pursuant to 35 IAC 217.756(f)(3).

iii. Any provision of the NO_x Trading Program that applies to a budget EGU (including any provision applicable to the account representative of a budget EGU) shall also apply to the owner and operator of such budget EGU. Except with regard to requirements applicable to budget EGUs with a common stack under 40 CFR 96, Subpart H, the owner and operator and the account representative of one budget EGU shall not be liable for any violation by any other budget EGU of which they are not an owner or operator or the account representative, pursuant to 35 IAC 217.756(f)(4).

d. Requirements for NO_x Allowances

i. By November 30 of each year, the allowance transfer deadline, the account representative of each budget EGU at this source shall hold allowances available for compliance deduction under 40 CFR 96.54 in the budget EGU's compliance account or the source's overdraft account in an amount that shall not be less than the budget EGU's total tons of NO_x emissions for the preceding control period, rounded to the nearest whole ton, as determined in accordance with 40 CFR 96, Subpart H, plus any number necessary to account for actual utilization (e.g., for testing, start-up, malfunction, and shut down under 40 CFR 96.42(e) for the control period, pursuant to 35 IAC 217.756(d)(1). For purposes of this requirement, an allowance may not be utilized for a control period in a year prior to the year for which the allowance is allocated, pursuant to 35 IAC 217.756(d)(5).

ii. The account representative of a budget EGU that has excess emissions in any control period, i.e., NO_x emissions in excess of the number of NO_x allowances held as provided above, shall surrender the allowances as required for deduction under 40 CFR 96.54(d)(1), pursuant to 35 IAC 217.756(f)(5). In addition, the owner or operator of a budget EGU that has excess emissions shall pay any fine, penalty, or assessment, or comply with any other remedy imposed under 40 CFR 96.54(d)(3) and the Act, pursuant to 35 IAC 217.756(f)(6). Each ton of NO_x emitted in excess of the number of NO_x allowances held as provided above for each budget EGU for each control period shall constitute a separate violation of 35 IAC Part 217 and the Act, pursuant to 35 IAC 217.756(d)(2).

iii. An allowance allocated by the Illinois EPA or USEPA under the NO_x Trading Program is a limited authorization to emit one ton of NO_x in accordance with the NO_x Trading Program. As explained by 35 IAC 217.756(d)(6), no provision of the NO_x Trading Program, the budget permit application, the budget permit, or a retired unit exemption under 40 CFR 96.5 and no provision of law shall be construed to limit the authority of the United States or the State of Illinois to terminate or limit this authorization. As further explained by 35 IAC 217.765(d)(7), an allowance allocated by the Illinois EPA or USEPA under the NO_x Trading Program does not constitute a property right. As provided by 35 IAC 217.756(c)(4), allowances shall be held, deducted from, or transferred among allowance accounts in accordance with 35 IAC Part 217, Subpart W, and 40 CFR 96, Subparts F and G.

e. Monitoring Requirements for Budget EGU

i. The Permittee shall comply with the monitoring requirements of 40 CFR Part 96, Subpart H, for each budget EGU and the compliance of each budget EGU with the emission limitation under Condition 3(d)(i) shall be determined by the emission measurements recorded and reported in accordance with 40 CFR 96, Subpart H, pursuant to 35 IAC 217.756(c)(1), (c)(2) and (d)(3).

ii. The account representative for the source and each budget EGU at the source shall comply with those sections of the monitoring requirements of 40 CFR 96, Subpart H, applicable to an account representative, pursuant to 35 IAC 217.756(c)(1) and (d)(3).

f. Recordkeeping Requirements for Budget EGU

Unless otherwise provided below, the Permittee shall keep on site at the source each of the following documents for a period of at least 5 years from the date the document is created. This 5-year period may be extended for cause at any time prior to the end of the 5 years, in writing by the Illinois EPA or the USEPA.

i. The account certificate of representation of the account representative for the source and each budget EGU at the source and all documents that demonstrate the truth of the statements in account certificate of representation, in accordance with 40 CFR 96.13, as provided by 35 IAC 217.756(e)(1)(A). These certificates and documents must be retained on site at the source for at least 5-years after they are superseded because of the submission of a new account certificate of representation changing the account representative.

ii. All emissions monitoring information, in accordance with 40 CFR 96, Subpart H, (provided that to the extent that 40 CFR 96, Subpart H, provides for a 3-year period for retaining records, the 3-year period shall apply,) pursuant to 35 IAC 217.756(e)(1)(B).

iii. Copies of all reports, compliance certifications, and other submissions and all records made or required under the NO_x Trading Program or documents necessary to demonstrate compliance with requirements of the NO_x Trading Program, pursuant to 35 IAC 217.756(e)(1)(C).

iv. Copies of all documents used to complete a budget permit application and any other submission under the NO_x Trading Program, pursuant to 35 IAC 217.756(e)(1)(D).

g. Reporting Requirements for Budget EGU

i. The account representative for this source and each budget EGU at this source shall submit to the Illinois EPA and USEPA the reports and compliance certifications required under the NO_x Trading Program, including those under 40 CFR 96, Subparts D and H and 35 IAC 217.774, pursuant to 35 IAC 217.756(e)(2).

ii. These submittals need only be signed by the designated representative, who may serve in place of the responsible official for this purpose as provided by the Section 39.5(1) of the Act, and submittals to the Illinois EPA need only be made to the Illinois EPA, Bureau of Air, Compliance and Enforcement Section.

h. Allocation of NO_x Allowances to Budget EGU

i. For the first four control periods that a budget EGU identified in Condition 3(b) operates, it will not be entitled to direct allocations of NO_x allowances because the EGU will be considered a "new" budget EGU, as defined in 35 IAC 217.768(a)(1).

ii. A. Thereafter, the budget EGU will cease to be "new" budget EGU and the source will be entitled to an allocation of NO_x allowances for the budget EGU as provided in 35 IAC 217.764. For example, for 2010, the allocation of NO_x allowances would be governed by 35 IAC 217.764(e)(2) and (b)(4).

B. In accordance with 35 IAC 217.762, the theoretical number of NO_x allowances for these budget EGU, calculated as the product of the applicable NO_x emissions rate and heat input as follows, shall be the basis for determining the allocation of NO_x allowances to these EGU:

1. As provided by 35 IAC 217.762(a)(2), the applicable NO_x emission rates for these EGU is 0.010 lb/million Btu or such lower limit as set pursuant to Unit-Specific Condition 1.15. This is the permitted emission rate for these EGU as contained in Unit-Specific Condition 1.2(b)(iii). The permitted NOx emission rate is the applicable rate because it is between 0.15 lb/million Btu and 0.055 lb/million Btu, as provided by 35 IAC 217.762(a)(2).

2. The applicable heat input (million Btu/control period) shall be the average of the two highest heat inputs from the control periods four to six years prior to the year for which the allocation is being made, as provided by 35 IAC 217.762(b)(1).

   Note: If the start of the NO_x Trading program is shifted because of a Court Decision, the years defining the different control periods would be considered to be adjusted accordingly, as provided by the Board note following 35 IAC 217.764.

i. Eligibility for NO_x Allowances from the New Source Set-Aside (NSSA)

The Permittee is eligible to obtain NO_x allowances for the budget EGU identified in Condition 3(b) from the NSSA, as provided by 35 IAC 217.768, because the budget EGU are "new" budget EGU.

j. Budget Permit Required by the NO_x Trading Program

i. For this source, this condition of this permit, i.e., Trading Program Condition 3, is the Budget Permit required by the NO_x Trading Program and is intended to contain federally enforceable conditions addressing all applicable NO_x Trading Program requirements. This Budget Permit shall be treated as a complete and segregable portion of this permit, as provided by 35 IAC 217.758(a)(2).

ii. The Permittee and any other owner or operator of this source and each budget EGU at the source shall operate the budget EGU in compliance with this Budget Permit, pursuant to 35 IAC 217.756(b)(2).

iii. No provision of this Budget Permit or the associated application shall be construed as exempting or excluding the Permittee, or other owner or operator and, to the extent applicable, the account representative of a budget source or budget EGU from compliance with any other regulation or requirement promulgated under the CAA, the Act, the approved State Implementation Plan, or other federally enforceable permit, pursuant to 35 IAC 217.756(g).

iv. Upon recordation by USEPA, under 40 CFR 96, Subparts F or G, or 35 IAC 217.782, every allocation, transfer, or deduction of an allowance to or from the budget EGU's compliance accounts or to or from the overdraft account for the budget source is deemed to amend automatically, and become part of, this budget permit, pursuant to 35 IAC 217.756(d)(8). This automatic amendment of this budget permit shall be deemed an operation of law and will not require any further review.

v. No revision of this Budget Permit shall excuse any violation of the requirements of the NO_x Trading Program that occurs prior to the date that the revisions to this permit takes effect, pursuant to 35 IAC 217.756(f)(1).

vi. The Permittee, or other owner or operator of the source, shall reapply for a Budget Permit for the source as required by 35 IAC Part 217, Subpart W and Section 39.5 of the Act. For purposes of the NO_x Trading Program, the application shall contain the information specified by 35 IAC 217.758(b)(2).

SECTION 6: GENERAL PERMIT CONDITIONS

GENERAL PERMIT CONDITION 1: STANDARD CONDITIONS

Standard conditions for issuance of construction permits, attached hereto shall apply to this project, unless superseded by provisions of other permit conditions.

GENERAL PERMIT CONDITION 2: REQUIREMENTS FOR EMISSION TESTING

a. i. At least 60 days prior to the actual date of initial emission testing required by this permit, a written test plan shall be submitted to the Illinois EPA for review. This plan shall describe the specific procedures for testing and shall include at a minimum:

A. The person(s) who will be performing sampling and analysis and their experience with similar tests.

B. The specific conditions, e.g., operating rate and control device operating conditions, under which testing shall be performed including a discussion of why these conditions are appropriate and the means by which the operating parameters will be determined.

C. The specific determinations of emissions that are intended to be made, including sampling and monitoring locations. As part of this plan, the Permittee may set forth a strategy for performing emission testing in the normal load range of the boilers.

D. The test method(s) that will be used, with the specific analysis method if the method can be used with different analysis methods.

ii. As provided by 35 IAC 283.220(d), the Permittee need not submit a test plan for subsequent emission testing that will be conducted in accordance with the procedures used for previous tests accepted by the Illinois EPA or the previous test plan submitted to and approved by the Illinois EPA, provided that the Permittee's notification for testing, as required below, contains the information specified by 35 IAC 283.220(d)(1)(A), (B) and (C).

b. i. The Permittee shall notify the Illinois EPA prior to performing emission testing required by this permit to enable the Illinois EPA to observe the tests. Notification for the expected date of testing shall be submitted a minimum of 30 days* prior to the expected date, and identify the testing that will be performed. Notification of the actual date and expected time of testing shall be submitted a minimum of 5 working days* prior to the actual date of testing.

* For a particular test, the Illinois EPA may at its discretion accept shorter advance notification provided that it does not interfere with the Illinois EPA's ability to observe testing.

ii. This notification shall also identify the parties that will be performing testing and the set or sets of operating conditions under which testing will be performed.

c. Three copies of the Final Reports for emission tests shall be forwarded to the Illinois EPA within 30 days after the test results are compiled and finalized. At a minimum, the Final Report for testing shall contain:

i. General information, i.e., testing personnel and test dates;

ii. A summary of results;

iii. Description of test method(s), including a description of sampling points, sampling train, analysis equipment, and test schedule;

iv. The operating conditions of the emission unit and associated control devices during testing and any work practice standard established for the unit as result of testing;

v. Data and calculations, including copies of all raw data sheets and records of laboratory analysis, sample calculations, and data on equipment calibration.

GENERAL PERMIT CONDITION 3: REQUIREMENTS FOR RECORDS FOR DEVIATIONS

Except as specified in a particular provision of this permit or in a subsequent CAAPP Permit for the plant, records for deviations from applicable emission standards and control requirements shall include at least the following information: the date, time and estimated duration of the event; a description of the event; the applicable requirement(s) that were not met; the manner in which the event was identified, if not readily apparent; the probable cause for deviation, if known, including a description of any equipment malfunction/breakdown associated with the event; information on the magnitude of the deviation, including actual emissions or performance in terms of the applicable standard if measured or readily estimated; confirmation that standard procedures were followed or a description of any event-specific corrective actions taken; and a description of any preventative measures taken to prevent future occurrences, if appropriate.

GENERAL PERMIT CONDITION 4: RETENTION AND AVAILABILITY OF RECORDS

Except as specified in a particular provision of this permit or in a subsequent CAAPP Permit for the plant, the Permittee shall keep all records, including written procedures and logs, required by this permit at a readily accessible location at the plant for at least five years and shall make such records available for inspection and copying by the Illinois EPA and USEPA.

GENERAL PERMIT CONDITION 5: NOTIFICATION OR REPORTING OF DEVIATIONS

Notifications and reports for deviation from applicable emission standards, control requirements, and compliance procedures shall be submitted as follows, except as specified in a particular provision of this permit or in a subsequent CAAPP Permit for the plant:

a. Notification and reports for deviations include at least the following information: a description of the event, the date and time or duration of the event, information on the magnitude of the deviation, a description of the corrective measures taken, and a description of any preventative measures taken to prevent future occurrences.

b. Exceedances of applicable emissions standards or limitations during periods of startup, malfunction or breakdown, or shutdown shall be considered deviations for purposes of notification and reporting, even if exceedance of the standard or limitation is otherwise provided for by applicable rule or this permit.

GENERAL PERMIT CONDITION 6: GENERAL REQUIREMENTS FOR NOTIFICATION AND REPORTS

a. i. Two copies of notifications and reports required by this permit shall be sent to the following address unless otherwise indicated above:

Illinois Environmental Protection Agency
Division of Air Pollution Control
Compliance and Enforcement Section
P.O. Box 19276
Springfield, Illinois 62794-9276

ii. One copy of notifications and reports required by this permit, except the Annual Emission Report required by 35 IAC Part 254, shall be sent to the Illinois EPA's regional office at the following address unless otherwise indicated above:

Illinois Environmental Protection Agency
Division of Air Pollution Control
9511 West Harrison
Des Plaines, Illinois 60123

b. Quarterly reports shall cover calendar quarters and be submitted no later than 45 days after the end of the calendar quarter if a shorter deadline is not specified in a particular provision of this permit.

c. The Permittee shall submit Annual Emission Reports to the Illinois EPA in accordance with 35 IAC Part 254. For hazardous air pollutants, this report shall include emission information for at least the following pollutants: hydrogen chloride, hydrogen fluoride, mercury, arsenic, beryllium, cadmium, chromium, lead, manganese, and nickel.

ATTACHMENT - TABLES

TABLE I

Emission Limitations for Each CFB Boiler

Pollutant	Pound/Million Btu[1]	Pounds/Hour[2]	Tons/Year	Combined Tons/Year
PM/PM_{10}[3]	0.015	43.8	192	384
NO_x[4]	0.10[4]	292.2	1,280	2,560
SO_2	0.15	438.3	1,920	3,840
CO	0.11[5]	321.4	1,408	2,816
VOM	0.004[5]	11.7	51.2	102.4
Fluorides[6]	----	5.7	25.1	50.2
Sulfuric Acid Mist	----	1.2	5.1	10.2
Beryllium	----	----	----	0.004
Hydrogen Chloride	----	----	----	256
Hydrogen Fluoride	----	----	----	50.2
Mercury	----	----	----	0.05
Lead	----	----	----	0.31

Notes:

1 Compliance with the emission rates expressed in pound/million Btu heat input shall be determined in accordance with the provisions in Condition 1.2(b).

2 Compliance with hourly emission limits shall be based on 24-hour block averages (NO_x, CO and SO_2) and 3-hour block average (VOM, PM/PM_{10}, fluorides, and sulfuric acid mist. Short-term emission rates do not apply during startup, shutdown or malfunction as addressed by Condition 1.6.

3 All particulate matter (PM) measured by USEPA Method 5 shall be considered PM_{10} unless PM emissions are tested by USEPA Method 201 or 201A, as specified in 35 IAC 212.108(a). These PM limits do not address condensable particulate matter. (Condensable particulate was addressed in the particulate matter air quality impact analysis required by the PSD rules. For this purpose, the emission rate for condensable particulate matter was estimated to be 0.035 lb/million Btu.)

4 The NO_x limits are phased, with an initial limit for the demonstration period, and provision for an even lower limit, which limit could be as low as 0.08 pound per million Btu, pursuant to the optimization program required by Conditions 1.2(d) and 1.15.

5 As an alternative to this limitation expressed in pound/million Btu, the boiler may comply with the limitation expressed in pounds/hour.

6 The limit for fluorides is expressed in terms of hydrogen fluorides.

TABLE II

Emission Limitations for
Certain Bulk Material Preparation Operations Involving Gas Combustion

(Pounds per Hour and Tons per Year)

Emission Unit	PM		CO		NO_x		VOM	
	Hourly Rate	Annual Rate	Hourly Rate	Annual Rate	Hourly Rate	Annual Rate	Hourly Rate	Annual Rate
Limestone Preparation								
Dryer/Mill System 1	0.24	1.05	2.4	10.5	0.9	3.85	0.24	1.05
Dryer/Mill System 2	0.24	1.05	2.4	10.5	0.9	3.85	0.24	1.05
Dryer/Mill System 3	0.24	1.05	2.4	10.5	0.9	3.85	0.24	1.05
Totals		3.15		31.5		11.5		3.2

TABLE III

Particulate Matter (PM) Emission Limitations for
Bulk Material Handling Operations

(Grains Per Dry Cubic Foot, Pounds Per Hour, and Tons Per Year)

Emission Units	Exhaust Loading	Hourly Rate	Annual Rate
Receiving and Handling			
Railcar Unloading, Transfer House, Crusher Building, Hoppers, etc., Except as Below	0.001	0.714	3.13
Limestone Reclaim	0.005	0.086	0.38
Material Storage Buildings	--	--	0.24
Subtotal		0.80	3.75
Limestone Preparation			
Preparation Equipment, Except as Below	0.001	0.270	0.117
Dryer/Mill System 1*	0.001	0.240	1.05
Dryer/Mill System 2*	0.001	0.240	1.05
Dryer/Mill System 3*	0.001	0.240	1.05
Limestone and Infeed Silos	0.005	0.621	2.73
Subtotal		1.354	7.05
Ash Handling and Loadout			
Bed Ash Silos, Transport Systems, Fly Ash Silos, etc., Except as Below	0.001	0.428	1.88
Fly Ash Hoppers	0.005	0.026	0.12
Bed and Fly Ash Loadout	--	--	0.036
Subtotal		0.454	2.04
Total		--	12.84

* See also Table II

ATTACHMENT - ACID RAIN PERMIT

217-782-2113

ACID RAIN PROGRAM PERMIT

Indeck-Elwood Energy Center
Attn: Mr. Thomas M Campone, Designated Representative
600 North Buffalo Grove Road, Suite 300
Buffalo Grove, Illinois 60089

Oris No.:	55823
Illinois EPA I.D. No.:	197035AAJ
Source/Unit:	Indeck-Elwood Energy Center, Unit 1 and 2
Date Received:	May 13, 2002
Date Issued:	October 10, 2003
Effective Date:	January 1, 2006
Expiration Date:	December 31, 2010

STATEMENT OF BASIS:

In accordance with Section 39.5(17)(b) of the Illinois Environmental Protection Act and Titles IV and V of the Clean Air Act, the Illinois Environmental Protection Agency is issuing this Acid Rain Program permit for the Indeck-Elwood Energy Center.

SULFUR DIOXIDE (SO_2) ALLOCATIONS AND NITROGEN OXIDE (NO_X) REQUIREMENTS FOR EACH AFFECTED UNIT:

Unit 1 and Unit 2	SO_2 Allowances	These Units are Not Entitled to an Allocation of SO_2 Allowances Pursuant to 40 CFR Part 73
	NO_x Emission Limitation	These Units are Not Subject to a NO_x Emissions Limitation Under 40 CFR Part 76.

This Acid Rain Program permit contains provisions related to sulfur dioxide (SO_2) emissions and requires the owners and operators to hold SO_2 allowances to account for SO_2 emissions beginning in the year 2000. An allowance is a limited authorization to emit up to one ton of SO_2 during or after a specified calendar year. Although this plant is not eligible for an allowance allocated by USEPA, the owners or operators may obtain SO_2 allowances to cover emissions from other sources under a marketable allowance program. The transfer of allowances to and from a unit account does not necessitate a revision to this permit (See 40 CFR 72.84).

This permit contains provisions related to nitrogen oxide (NO_x) emissions requiring the owners or operators to monitor NO_x emissions from affected units in accordance with the applicable provisions of 40 CFR Part 75.

This Acid Rain Program permit does not authorize the construction and operation of the affected units as such matters are addressed by Titles I and V of the Clean Air Act. If the construction and operation of one of the affected units is not undertaken, this permit shall not cover such unit.

In addition, notwithstanding the effective date of this permit as specified above, this permit shall not take effect for an individual affected unit until January 1 of the year in which the unit commences operation.

COMMENTS, NOTES AND JUSTIFICATIONS:

This permit does not affect the owners and operators responsibility to meet all other applicable local, state, and federal requirements, including requirements addressing SO_2 and NO_x emissions.

PERMIT APPLICATION:

The SO_2 allowance requirements and other standard requirements as set forth in the application are incorporated by reference into this permit. The owners and operators of this source must comply with the standard requirements and special provisions set forth in the application.

If you have any questions regarding this permit, please contact Mohamed Anane at 217/782-2113.

Donald E. Sutton, P.E.
Manager, Permits Section
Division of Air Pollution Control

DES:MA:jar

cc: Cecilia Mijares, USEPA Region V
Illinois EPA Region 1

ATTACHMENT - STANDARD PERMIT CONDITIONS

STANDARD CONDITIONS FOR CONSTRUCTION/DEVELOPMENT PERMITS
ISSUED BY THE ILLINOIS ENVIRONMENTAL PROTECTION AGENCY

The Illinois Environmental Protection Act (Illinois Revised Statutes, Chapter 111-1/2, Section 1039) authorizes the Environmental Protection Agency to impose conditions on permits which it issues.

The following conditions are applicable unless superseded by special condition(s).

1. Unless this permit has been extended or it has been voided by a newly issued permit, this permit will expire one year from the date of issuance, unless a continuous program of construction or development on this project has started by such time.

2. The construction or development covered by this permit shall be done in compliance with applicable provisions of the Illinois Environmental Protection Act and Regulations adopted by the Illinois Pollution Control Board.

3. There shall be no deviations from the approved plans and specifications unless a written request for modification, along with plans and specifications as required, shall have been submitted to the Illinois EPA and a supplemental written permit issued.

4. The Permittee shall allow any duly authorized agent of the Illinois EPA upon the presentation of credentials, at reasonable times:

   a. To enter the Permittee's property where actual or potential effluent, emission or noise sources are located or where any activity is to be conducted pursuant to this permit,

   b. To have access to and to copy any records required to be kept under the terms and conditions of this permit,

   c. To inspect, including during any hours of operation of equipment constructed or operated under this permit, such equipment and any equipment required to be kept, used, operated, calibrated and maintained under this permit,

   d. To obtain and remove samples of any discharge or emissions of pollutants, and

   e. To enter and utilize any photographic, recording, testing, monitoring or other equipment for the purpose of preserving, testing, monitoring, or recording any activity, discharge, or emission authorized by this permit.

5. The issuance of this permit:

   a. Shall not be considered as in any manner affecting the title of the premises upon which the permitted facilities are to be located,

   b. Does not release the Permittee from any liability for damage to person or property caused by or resulting from the construction, maintenance, or operation of the proposed facilities.

   c. Does not release the Permittee from compliance with other applicable statutes and regulations of the United States, of the State of Illinois, or with applicable local laws, ordinances and regulations.

   d. Does not take into consideration or attest to the structural stability of any units or parts of the project, and

   e. In no manner implies or suggests that the Illinois EPA (or its officers, agents or employees) assumes any liability, directly or indirectly, for any loss due to damage, installation, maintenance, or operation of the proposed equipment or facility.

6. a. Unless a joint construction/operation permit has been issued, a permit for operation shall be obtained from the Illinois EPA before the equipment covered by this permit is placed into operation.

   b. For purposes of shakedown and testing, unless otherwise specified by a special permit condition, the equipment covered under this permit may be operated for a period not to exceed thirty (30) days.

7. The Illinois EPA may file a complaint with the Board for modification, suspension or revocation of a permit.

   a. Upon discovery that the permit application contained misrepresentations, misinformation or false statement or that all relevant facts were not disclosed, or

   b. Upon finding that any standard or special conditions have been violated, or

   c. Upon any violations of the Environmental Protection Act or any regulation effective thereunder as a result of the construction or development authorized by this permit.

EXHIBIT 5

United States Department of the Interior

FISH AND WILDLIFE SERVICE
Rock Island Field Office
4469 48th Avenue Court
Rock Island, Illinois 61201
Phone: (309) 793-5800 Fax: (309) 793-5804

IN REPLY REFER TO:

FWS/RIFO

RECEIVED
JUN 2006
AIR PROGRAMS BRANCH

June 21, 2006

Ms. Pamela Blakley
U.S. Environmental Protection Agency
77 West Jackson Boulevard
Chicago, Illinois 60604-3590

Dear Ms. Blakley:

This responds to your June 13, 2006, letter in which you request for our concurrence pursuant to Section 7 of Endangered Species Act for the Prevention of Significant Deterioration (PSD) permit for the proposed City of Springfield Dallman Unit number 4 power plant. We have reviewed the information provided in your letter, biological evaluation, related attachments, and have coordinated with your staff.

We concur with your findings that approval of this PSD permit will not adversely affect the federally listed bald eagle and Indiana bat species in the action area defined in the biological evaluation. This precludes the need for further action on this project as required under Section 7 of the Endangered Species Act of 1973, as amended. Should the project be modified or new information indicate endangered species may be affected, consultation should be initiated.

This letter provides comments under the authority of and in accordance with provisions of the Endangered Species Act of 1973, as amended (87 Stat. 884, as amended; 16 U.S.C. 1531 *et seq.*)

Thank you for the opportunity to coordinate with you on this matter. Please feel free to call me at extension 201 or Mike Coffey of my staff at extension 206 if you have any questions or wish to discuss this further.

Sincerely,

Richard C. Nelson
Field Supervisor

[redacted]

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 5
77 WEST JACKSON BOULEVARD
CHICAGO, IL 60604-3590

JUN 13 2006

REPLY TO THE ATTENTION OF

(AR-18J)

Richard Nelson, Field Supervisor
Rock Island Illinois Field Office
United States Fish and Wildlife Service
4469 48th Avenue Court
Rock Island, Illinois 61201

Dear Mr. Nelson:

Pursuant to Section 7 of the Endangered Species Act (ESA), (87 Stat. 884, as amended; 16 U.S. C. 1531 et seq.), the United States Environmental Protection Agency (USEPA) has reviewed the biological information and analysis related to a Prevention of Significant Deterioration (PSD) permit for The City of Springfield, City Water, Light and Power (CWLP) Dallman Unit 4 to determine what impact there may be to any threatened or endangered species in the area around the proposed facility. The purpose of this letter is to seek concurrence from the United States Fish and Wildlife Service (USFWS) on our determination that the proposed project is not likely to adversely affect any federally listed species in relation to the proposed air quality permit for this facility.

The parties utilized the informal consultation process as specified in the "Endangered Species Consultation Handbook, procedures for conducting consultation and conference activities under Section 7 of the Endangered Species Act, (March 1998 final)," by the USFWS and National Marine Fisheries Service. The USEPA prepared this biological assessment following the guidance provided in the ESA consultation handbook, as well as the recommended content suggested in the ESA regulations found in 50 CFR Part 402.12(f). Additionally, USFWS provided USEPA a draft recommended scope of analysis on January 20, 2006.

Project Description

CWLP has proposed to construct a new subcritical pulverized coal-fired boiler to power a steam turbine generator, associated pollution control equipment, auxiliary equipment, cooling tower, and materials handling equipment. The new boiler will have a nominal new power output of approximately 250 MW and will provide base load power to the electric grid on a continual basis. As part of this project, CWLP will retire two existing units, Lakeside units 6 and 7. The projected will result in increases in three criteria air pollutants, carbon monoxide (CO), particulate matter (PM), and volatile organic compounds (VOC), in the amount of 1249.41 tons per year, 394.67 tons per year, and

[redacted]

31.46 tons per year respectively. The project will result in decreases in emissions for nitrogen oxides (NOx), sulfur dioxide (SO_2)and lead, with SO_2 emissions decreasing by 5605.71 tons per year. The project is expected to result in increased emission of certain metals, dioxins and furans. The projected emission levels are listed in Table 1 of the document "Supplement to Part 7 of PSD Permit Application: Additional Impact Analysis for Metals," which is included as Attachment 1.

Action Area

The CWLP site encompasses approximately 100 acres in Sangamon County. It is located near Lake Springfield in Section 13 of Township 15 North, Range 5 West.

List of Species

The species potentially occurring in the vicinity of the facility include the Eastern prairie fringed orchid (Platanthera leucophaea), the Prairie bush clover (Lespedeza leptostachya), the Bald eagle (Haliaeetus leucocephalus), and the Indiana bat (Myotis sodalis).

While the Eastern prairie fringed orchid and the Prairie bush clover are listed as statewide species, the USFWS informed USEPA in an e-mail dated March 13, 2006, that these species are not known to occur in Sangamon County. The USFWS indicated that the bald eagle and Indiana bat should be included in the evaluation.

The Indiana bat is listed as a statewide species. While there have been no known occurrences within the action area, there is suitable habitat. There are known summer populations in the counties to the west and east of Sangamon County. The bald eagle may be found during the summer or winter throughout much of Illinois, and suitable habitat is present in southern Sangamon County.

Summary of Analysis

In an October 29, 2005, letter, the Illinois Environmental Protection Agency (IEPA) requested that USEPA initiate consultation with USFWS under the ESA. In November 2005, USEPA contacted the Rock Island Field Office via telephone requesting that an informal consultation process by initiated for this project. On January 20, 2006, USFWS provided a draft document titled "Recommended Scope of Analysis for City of Springfield (CWLP) Dallman Unit 4 for Endangered Species Evaluation." On February 2, 2006, USEPA and USFWS held a conference call to discuss the draft document and any remaining areas of concern. USEPA has conducted this analysis in accordance with this scoping document and the information obtained during the February 2, 2006, call.

The scoping document provided by USFWS indicated that the modeling for this analysis should follow the general guidance provided in Chapter 3 of USEPA's Screening-Level Ecological Risk Assessment (SLERA) protocol for assessing chemical fate and transport, the modeling should show air concentrations and deposition rates for appropriate

pollutants, and that the total impacts should be evaluated looking at the combined effects of the vapor phase, particle phase and particle-bound phase of pollutants. The document indicated that ISCST3 was an acceptable model for the analysis. In addition, the document indicated that the evaluation should take into account the addition of Unit 4 as well as the shut down of the Lakeside Units 6 and 7.

ESA Effects Analysis

Criteria Pollutants

The project at CWLP will result in decreases in emissions for NOx of 192.61 tons per year and for SO_2 of 5605.71 tons per year. The project will also result in a small decrease in lead emissions. The local background soil concentration for lead is 36 mg/kg. The maximum modeled deposition concentration for lead of 0.236 mg/kg is less than 1% of background. Reductions in emissions are expected to be beneficial for the species. USEPA has concluded that the project is not likely to adversely effect the Indiana bat and the Bald eagle with respect to these pollutants.

The project will result in a small increase in VOC emissions of 31.46 tons per year. At the current time, USEPA is unaware of any reliable means to assess ozone changes through "point source" modeling. Although point source screening models have been developed, they have not been consistently applied with success for source changes of this small magnitude. Such screening models were developed for much larger VOC and NOx sources and/or emissions changes. Urban scale photochemical ozone models, such as the Urban Airshed Model, could be employed to assess the ambient impact of emission increases as well as emission decreases resulting from the implementation of emissions control programs. Past experience, however, with such models indicates that a VOC change of 31.46 tons per year would not produce a predicted change in ozone concentrations. The Urban Airshed Model, for example, has been shown to be relatively insensitive to changes in VOC emissions. Past modeling results considering VOC emissions changes on the order of hundreds to several thousand tons per year of VOC in major urban areas have shown only modest decreases in predicted peak ozone concentrations. Therefore, it is concluded that such models would likely show a zero ozone change for a VOC increase of 31.46 tons per year. Stated another way, based on the best available tools and information that exist today, one would not expect any measurable change in ambient ozone concentrations due to the Project's projected worst case VOC emissions increase of 31.46 tons per year. Based on this information, USEPA concludes the project will have no measurable effect, if not no effect, on the endangered species with respect to ozone. At a minimum, the project is not likely to adversely effect the endangered species as no measurable change in ozone will result from the project.

Hazardous Air Pollutants

The project will result in small increases in emissions of metals, dioxins, and furans. These maximum ground level concentrations of these pollutants are listed in Table 1 of

CWLP's analysis, which has been included as Attachment 1. Table 2 of CWLP's analysis shows the maximum modeled deposition concentration in comparison to the screening level and local background for each pollutant. With respect to the bald eagle an the Indiana bat, the main concern is metals and dioxins/furans bioaccumulation throughout the food web. Further analysis performed by USEPA is included as Attachment 2. The CWLP and USEPA analyses show that the impacts from this project are below the selected screening levels. Based on this information USEPA has found that the project is not likely to adversely affect the two species in question.

ESA Determination

After review of the likely effects of the proposed project, it would appear that the main area of concern is the impact of metals and dioxins/furans. The screening level models used to predict deposition concentrations for these pollutants, show levels below the conservative screening values used.

Considering this analysis in its entirety, USEPA concludes that the proposed construction and operation of this facility may affect, but is not likely to adversely affect, any the threatened and endangered species. USEPA respectfully requests USFWS concurrence on this determination.

Sincerely yours,

Pamela Blakley

Pamela Blakley, Chief
Air Permits Section

Attachments

cc: Laurel Kroak, IEPA

Attachment 1
City Water, Light and Power
Supplement to Part 7 of PSD Permit Application:
Additional Impact Analysis for Metals

An impact analysis of Dallman Unit 4 boiler's metal emissions was made as part of the Additional Impacts Analysis (Part 7 of the PSD Permit Application, revised in June 2005) required by PSD regulations. This supplement discusses the impacts of emitted metals on soils and plants from the Dallman Unit 4 project and was accomplished using the EPA-approved protocol "Screening Level Ecological Risk Assessment Protocol for Hazardous Wasted Combustion Facilities, Chapter 3: Air Dispersion and Deposition Modeling".

In addition to criteria pollutants, other materials are present in the coal or can be formed as a by-product of combustion in the boiler and have the potential to be emitted in small quantities. The metal elements that can be emitted may have an adverse effect on plants and soils. Emission estimates for metals are based on emission factors taken from AP-42 Section 1.1, *Bituminous and Subbituminous Coal Combustion* (9/98). Several assumptions were made to allow for a "worst-case" calculation of emissions. It is assumed that the boiler will burn coal at the rate of 2,438 MMBtu per hour for the entire year (8,760 hours), and the firing process will release all of these contaminants contained in the coal. None of these pollutants were assumed to be entrained in the bottom ash and the control devices available will be the SCR, the wet FGD, and a fabric filter. In actuality, the unit will operate for less than 8,760 hours annually and some of the material will be captured in the bottom ash while other material will be more effectively removed in the SCR, wet FGD, and particulate control systems (fabric filter and wet electrostatic precipitator).

The emission rates of each of the metals that may be emitted from the Dallman Unit 4 boiler were modeled using the EPA-approved ISC model in the same manner as the criteria pollutants (described in Section 6 of the PSD Permit Application) and annual impacts were obtained for each. In addition, because deposition was used in the modeling process meteorological data along with some additional inputs into ISC needed to be adjusted according to the EPA's document, "Screening Level Ecological Risk Assessment Protocol for Hazardous Wasted Combustion Facilities". Meteorological data in ISC was determined using the following rural and grassland assumptions (tables can be found in Appendix A along with PCRAMET Log with these values):

- Monin-Obukhov Length: 25 meters for residential
- Anemometer height (known): 9.4488 meters

- Surface Roughness: 0.1 for grassland
- Albedo: 0.25875 average of the seasons for grassland (0.65 and 0.30 for winter)
- Bowen Ratio: 0.7 for grassland
- Anthropogenic heat flux: 0.0 for rural areas
- Net Radiation: 0.15 for rural areas

In addition to the meteorological data, deposition terms were associated into the model and included mean particle diameter (μg), fraction of total mass, density (g/cm^3) (assumed to be 1.0), and wet scavenging rate coefficient (hr/s-mm). The wet scavenging rate coefficient is a function of particle diameter. . The value is used for both liquid and frozen particle deposition.

Because the Dallman Unit 4 boiler has the potential to emit 99.99 percent of all HAPs emitted by this facility, only the metals, dioxins, and furans emitted from the Dallman Unit 4 boiler were included in this modeling. Metals present in the coal along with dioxins and furans are listed in Table 1 along with their emission factors and modeled ground level concentrations.

Table 1
Modeled Metal Emissions

Pollutant	Emission Rate* 100% Load on Coal (lb/hr)	Maximum Modeled Annual Ground Level Concentration (μg/m³)
Arsenic	0.049	9.00×10^{-5}
Cadmium	0.006	1.00×10^{-5}
Chromium	0.031	6.00×10^{-5}
Cobalt	0.012	2.00×10^{-5}
Fluorides	0.596	1.12×10^{-3}
Lead	0.050	9.00×10^{-5}
Manganese	0.059	1.10×10^{-4}
Mercury	0.005	1.00×10^{-5}
Nickel	0.034	6.00×10^{-5}
Selenium	0.156	2.90×10^{-4}
Dioxins	2.93×10^{-5}	0.00
Furans	2.93×10^{-5}	0.00

* Based on AP-42: Table 1.1-18 and maximum coal rate of 120.0 tons/hr.

In determining the effects that the metals, dioxins, and furans have on the soil, the deposition concentration of the trace elements on soils were calculated by using the screening techniques described in the EPA's document, "Screening Level Ecological Risk Assessment Protocol for

Hazardous Wasted Combustion Facilities", Section 3.11.1 – Calculation of COPC Concentrations in Soil. The formula for calculating the soil concentration is as follows:

$$Cs = \frac{Ds \cdot [1 - \exp(-ks \cdot tD)]}{ks}$$

Where:

CS = COPC (compound of particular concern) concentration in soil (mg COPC/kg soil)

Ds = Deposition Term (mg/kg-yr)

ks = COPC soil loss constant due to all processes (yr^{-1})

tD= Total time period over which deposition occurs (yr, assume 100 yrs)

The deposition term (Ds) and soil lost constant (ks) are both calculated using more in-depth equations/variables which are included in Appendix A. After applying above equation to the ground level concentrations that were modeled, the soil concentration was compared to the acceptable background and screening levels designated by the EPA, both values in (mg/kg). The background concentrations were taken from Tiered Approach to Corrected Action Objectives (TACO) appendix presented by the Illinois EPA. The background concentrations are specific to Illinois and are different for metropolitan/non metropolitan counties. Sangamon County, where the facility is located, is considered metropolitan. Background levels are not available for the fluorides, dioxins, and furans.

The soil screening levels used were No Observed Adverse Effect Levels (NOAEL) and are specific to different animals. The screening levels were taken from the "Toxicology Benchmarks for Wildlife: 1996 revision" given to the U.S. Department of Energy. For this particular ecological risk, the animals in of concern are the bald eagle and Indiana bat. The closest species for the analysis for the metals was the Great Blue Heron. Screening levels were available for all metals from this document. For the dioxins, the NOAEL level of 2,3,7,8-Tetrachloro Dibenzodioxin (TCDD) for a Ring Necked Pheasant was used to represent the closest available species and was the worst-case screening level for dioxins. TCDD is also considered the most toxic of all dioxins and is commonly used as a reference for all other dioxins. For the furans, the NOAEL level of 2,3,7,8-Tetrachloro Dibenzofuran (TDBF) for a Great Blue Heron was used to represent the worst-case screening level for furans.

Table 2, below, indicates that the calculated depositions concentrations (mg/kg) from the modeled results are well below the standard screening level for each metal and dioxin/furans. Likewise, Table 2 indicates that the soil concentrations are well below the local background concentrations.

Table 2
Trace Concentration Compared to Screening and Background Levels

Pollutant	Maximum Modeled Deposition Concentration (mg/kg)	Screening Level (mg/kg)	Local Background Concentration (mg/kg)
Arsenic	0.115	5.1	13
Cadmium	0.003	1.45	0.6
Chromium	0.093	1	16.2
Cobalt	3.89×10^{-5}	0.14	8.9
Fluorides	0.0096	7.8	N/A
Lead	0.236	3.85	36
Manganese	0.001	997	636
Mercury	6.30×10^{-4}	0.45	0.06
Nickel	0.077	77.4	18
Selenium	0.253	0.5	0.48
Dioxins	2.01×10^{-9}	1.40×10^{-5}	N/A
Furans	1.94×10^{-11}	1.00×10^{-6}	N/A

Pollutant	Emission Rate lb/hr	tpy	(g/s)
Arsenic	4.92E-02	2.15E-01	6.20E-03
Cadmium	6.12E-03	2.68E-02	7.71E-04
Chromium	3.12E-02	1.37E-01	3.93E-03
Cobalt	1.20E-02	5.26E-02	1.51E-03
Fluorides (Chlorine)	5.96E-01	2.61E+00	7.51E-02
Lead	5.04E-02	2.21E-01	6.35E-03
Manganese	5.88E-02	2.58E-01	7.41E-03
Mercury	5.25E-03	2.30E-02	6.61E-04
Nickel	3.36E-02	1.47E-01	4.23E-03
Selenium	1.56E-01	6.83E-01	1.97E-02
Dioxins	2.93E-05	1.28E-04	3.69E-06
Furans	2.93E-05	1.28E-04	3.69E-06

	Appendix A-2 Variables for each Metal (and Dioxins/Furans)				
Pollutant	Fv	Kds (pH=6.8) (cm^3/g)	Da (cm^2/s)	H (atm m^3/mol)	Source
Arsenic	0.00	29.00	0.1070	0.00	Appendix A-2, Table A-2-14, Page A-2-49
Cadmium	0.00	75.00	0.0816	0.00	Appendix A-2, Table A-2-35, Page A-2-71
Chromium	0.00	1.80E+06	0.1010	0.00	Appendix A-2, Table A-2-52, Page A-2-89
Cobalt	0.00	0.00	0.0000	0.00	None, Fv & H Assumed for all metals
Fluorides (Chlorine)	1.00	0.00	0.1100	0.00	Appendix A-2, Table A-2-39, Page A-2-75
Lead	0.00	900.00	0.0543	0.00	Appendix A-2, Table A-2-128, Page A-2-169
Manganese	0.00	0.00	0.0000	0.00	None, Fv & H Assumed for all metals
Mercury	1.00	1000.00	0.0109	7.10E-03	Appendix A-2, Table A-2-131, Page A-2-172
Nickel	0.00	65.00	0.1260	0.00	Appendix A-2, Table A-2-145, Page A-2-186
Selenium	0.00	5.00	0.1030	0.00	Appendix A-2, Table A-2-172, Page A-2-215
Dioxins	0.49	9.77E+05	0.0127	1.60E-05	[redacted]
Furans	1.00	3.72E+06	0.1310	5.30E-05	

Fv: Fraction of COPC air concentration in vapor phase
Kds (cm^3/g): soil-water partition coefficient
Da (cm^2/s): Diffusivity of COPC in air
H (atm m^3/mol) Henry's Law Constant

Variables for all Metals		Units	Source
tD time period	100	yr	Appendix B, Table B-1-1, Page B-3
Zs: Soil Mixing Depth (assumed Tilled)	20	cm	Appendix B, Table B-1-1, Page B-4
BD: Soil Bulk Density	1.5	g/cm^3	Appendix B, Table B-1-1, Page B-4
Vdv: Dry Deposition Velocity	3	cm/s	Appendix B, Table B-1-1, Page B-5
Kse: loss constant due to erosion	0	1/yr	Appendix B, Table B-1-3, Page B-14
θsw: Soil volumetric water constant	0.2	mL/cm^3	Appendix B, Table B-1-4, Page B-21
R : Universal Gas Constant	8.205E-05	atm-m^3/mol-K	Appendix B, Table B-1-6, Page B-32
Ta: Ambient Air Temperature	298	K	Appendix B, Table B-1-6, Page B-32
ρs: Solids Particle Density	2.7	g/cm^3	Appendix B, Table B-1-6, Page B-33
RO: Average annual surface runoff	25.4	cm/yr	USGS Map
P: Average Annual Precipitation	90.32	cm/yr	National Weather Service
I: Average Annual Irrigation	0	cm/yr	Per Don Pitts at Illinois Department of Water
Ev: Average Annual Evapotranspiration	76.2	cm/yr	USGS Map

Equations

$$Cs = \frac{Ds \cdot [1 - \exp(-ks \cdot tD)]}{ks}$$ concentration in soil (mg/kg)

$$Ds = \frac{100 \cdot Q}{Z_s \cdot BD} \cdot [F_v (0.31536 \cdot Vdv \cdot Cyv + Dywv) + (Dydp + Dywp) \cdot (1 - F_v)]$$ Deposition term (mg/kg-yr)

KS = Ksg +Kse + Ksr +Ksl +Ksv — soil loss constant due to all processes (1/yr)

Ksg = 0 For All Metals — loss constant due to abiotic and biotic degradation (1/yr)

Kse= 0 For Metals and Dioxins/Furans — loss constant due to soil erosion (1/yr)

$$ksr = \frac{RO}{\theta_{sw} \cdot Z_s} \cdot \left(\frac{1}{1 + (Kd_s \cdot BD / \theta_{sw})}\right)$$ loss constant due to surface runoff (1/yr)

$$ksl = \frac{P + I - RO - E_v}{\theta_{sw} \cdot Z_s \cdot [1.0 + (BD \cdot Kd_s / \theta_{sw})]}$$ loss constant due to leaching (1/yr)

$$ksv = \left[\frac{3.1536 \times 10^7 \cdot H}{Z_s \cdot Kd_s \cdot R \cdot T_a \cdot BD}\right] \cdot \left(\frac{D_a}{Z_s}\right) \cdot \left[1 - \left(\frac{BD}{\rho_s}\right) - \theta_{sw}\right]$$ loss constant due to volatization (1/yr)

Pollutant	Cyv (µg/m^3)	Deposition Dywp + Dydp g/m^2-yr	Dywv (g/m^2-yr)	Comments
Arsenic	9.00E-05	0.11181	0	Zero since Fv is zero
Cadmium	1.00E-05	0.01391	0	Zero since Fv is zero
Chromium	6.00E-05	0.07091	0	Zero since Fv is zero
Cobalt	2.00E-05	0.02727	0	Zero since Fv is zero
Fluorides	1.12E-03	1.35405	1.35405	Modeled
Lead	9.00E-05	0.11454	0	Zero since Fv is zero
Manganese	1.10E-04	0.13363	0	Zero since Fv is zero
Mercury	1.00E-05	0.01193	0.01193	Modeled
Nickel	6.00E-05	0.07636	0	Zero since Fv is zero
Selenium	2.90E-04	0.35454	0	Zero since Fv is zero
Dioxins	0.00E+00	0.00007	0.00007	Modeled
Furans	0.00E+00	0.00007	0.00007	Modeled

Cyv: Maximum Modeled Annual Ground Level Concentration (µg/m^3)

						With Depletion					
Pollutant	Ksr (1/yr)	Ksl (1/yr)	Ksv (1/yr)	Ksg (1/yr)	KS (1/yr)	DS (mg/kg-yr)	CS (mg/kg)	Background Concentration (mg/kg)	Screening Levels (mg/kg)	Exceed Background?	Exceed Screening?
Arsenic	2.91E-02	-1.29E-02	0.00E+00	0.00	1.62E-02	2.31E-03	1.15E-01	13	5.1	no	no
Cadmium	1.13E-02	-5.00E-03	0.00E+00	0.00	6.27E-03	3.58E-05	2.66E-03	0.6	1.45	no	no
Chromium	4.70E-07	-2.09E-07	0.00E+00	0.00	2.62E-07	9.29E-04	9.29E-02	16.2	1	no	no
Cobalt	6.35E+00	-2.82E+00	0.00E+00	0.00	3.53E+00	1.37E-04	3.89E-05	8.9	0.14	no	no
Fluorides	6.35E+00	-2.82E+00	0.00E+00	0.00	3.53E+00	3.39E-01	9.60E-02	N/A	7.8	N/A	no
Lead	9.41E-04	-4.18E-04	0.00E+00	0.00	5.23E-04	2.42E-03	2.36E-01	36	3.85	no	no
Manganese	6.35E+00	-2.82E+00	0.00E+00	0.00	3.53E+00	3.30E-03	9.35E-04	636	997	no	no
Mercury	8.47E-04	-3.76E-04	4.07E-02	0.00	4.11E-02	2.63E-05	6.30E-04	0.06	0.45	no	no
Nickel	1.30E-02	-5.77E-03	0.00E+00	0.00	7.23E-03	1.08E-03	7.67E-02	18	77.4	no	no
Selenium	1.65E-01	-7.32E-02	0.00E+00	0.00	9.17E-02	2.32E-02	2.53E-01	0.48	0.5	no	no
Dioxins	8.67E-07	-3.85E-07	1.09E-07	0.429	4.29E-01	8.61E-10	2.01E-09	N/A	1.40E-05	N/A	no
Furans	2.28E-07	-1.01E-07	9.81E-07	44.3	4.43E+01	8.61E-10	1.94E-11	N/A	1.00E-06	N/A	no

Attachment 2
USEPA Analysis

Additional analysis of CWLP screening data

April 13, 2006

The modeled maximum deposition composition for mercury represents total mercury and not what is bioavailable but we know the bioavailable portion is less than the total. The concentration of mercury contributed from the project is about 1 percent of the current estimated background so the risk analysis will not realistically be able to provide a meaningful number for a hazard estimate.

Bald Eagle

Risk calculations for higher trophic level animals such as Bald eagle can be quite complex but since the amount of additional mercury will be so small it should be sufficient to provide a simple evaluation to demonstrate that the result is not likely to adversely affect the species. Mercury does biomagnify and the Bald eagle will be exposed to mercury through its primary food source which is fish. Since the location of the project is away from a sizeable body of water and the Bald eagle's feeding area, it is expected that the additional mercury from the project will not contribute appreciably to the mercury load to Bald eagles near Springfield.

Indiana Bat

For the Indiana bat, a simple food web analysis was performed to evaluate a very conservative exposure scenario (see attached). Since only soil media concentrations are available, it was assumed that the exposure pathway is from soil and terrestrial insects to the bat (acknowledging that this does not represent the usual scenario for bats). A normalized dose for the bat was calculated to be 0.0008 which was compared to a mammalian (No Observed Adverse Effect Level for mink) toxicity reference value (TRV) of 1 mg/kg/day. This demonstrates an exposure far below the TRV and a hazard quotient value would be 0.0008 with 1 being the point when further analysis might be deemed necessary.

Screening Level Values

With regard to the screening level values provided in Table 2, the numbers are conservative. The USEPA has developed Eco-Soil Screening Levels (Ec0_SSLs) for arsenic, cadmium, chromium, cobalt, and lead, all of which are higher than the screening levels shown in the table. In Table 2 the screening levels are often below the background concentrations but the Eco-SSLs are not. These values can be found at www.epa.gov/ecotox/ecossl/. The resulting assessment of effect on species does not change but the information provided by comparing with the Eco-SSLs makes a better argument that there is not likely to be an adverse effect from the additional load of contaminants.

Additional Analysis for Springfield Dallman (CWLP)
to Include Aquatic Food Sources in Diet of Indiana Bat and Bald Eagle
June 2, 2006

Additional information was provided that indicates air deposition will occur over Lake Springfield. Therefore further analysis is provided to include aquatic food sources in the diet for the Bald eagle and Indiana bat.

Bald eagle

1. In the recent evaluation done for the Prairie State Generating Station Screening Level Ecological Risk Assessment an avian sediment screening level was calculated using EcoRiskView© software (available commercially) which uses draft USEPA guidance (1999). The avian sediment screening levels for mercury were:

    = 0.2 mg/kg for mercuric chloride
    = 0.2 mg/kg for methyl mercury

2. As provided by CWLP in "Supplement to Part 7 of PSD Permit Application – Additional Impact Analysis for Metals", the additional soil total mercury concentration (after 100 yrs) = 6.3E-04 mg/kg.

   For a worst case scenario, assume sediment concentration is 2 times the soil concentration (erosion of soil to water body w/ no loss, deposition to water body same as to soil and 100% ends up on surface of sediment)

    ∴ sediment conc. = 1.26E-03 mg/kg

3. Existing condition for surface sediments in central Illinois range from 200 – 500 ppb total mercury (per ISGS email on 6/1/06)

    ∴ assume existing total mercury sediment concentration for Lake Springfield is 0.5 mg/kg (as a worst case).

5. Future condition (existing + new) = 0.5 + 1.26E-03 = 0.50126 mg/kg

6. New contribution is 0.25% of the future condition for total mercury (using 0.5 mg/kg as the current condition). (Or 0.6% if the existing condition is deemed to be 0.2 mg/kg)

    ∴ Any effect from the additional mercury may not be measurable at these levels.

7. Total mercury does not represent the amount of mercury that is bioavailable. USEPA (1999) recommends using the assumption that mercury is 85% divalent & 15% methyl mercury.

8. Assuming 15% in methylated form (0.50126 mg/kg total Hg * .15 = 0.075 mg/kg).

9. 0.075 mg/kg methyl mercury < screening value of 0.2 mg/kg methyl mercury.

Without fish tissue or water column data any more refined analysis is not practical or defensible for this food web analysis.

Indiana bat

See revised spreadsheet and calculations on the attached. Several scenarios are presented showing different dietary amounts for terrestrial and aquatic insects. Since water column values are not available for the mercury this analysis is incomplete. In the scenarios presented the hazard quotients are less than one.

Reference:

USEPA. 1999. Screening Level Ecological Risk Assessment Protocol for Hazardous Waste Combustion Facilities. Peer Review Draft. EPA530-D-99-001A, August 1999.

Indiana bat (*Myotis sodalis*) food exposure pathway risk calculation for Springfield CWLP project (Version 1a)

Chemical: Mercury (methyl)

Assumptions: **15% methylation of sediments**

100% infaunal aquatic insects

Future Soil Concentration	0.00063	mg/Kg dw	total mercury
Existing Soil Concentration	0.06	mg/Kg dw	total mercury
Soil to Invert BAF	8.5	unitless	
Future Sediment Concentration	0.000189	mg/Kg dw	assume 15% methylation rate for sed total Hg conc of 0.00126 mg/kg
Existing Sediment Concentration	0.075	mg/Kg dw	assume 15% methylation rate for sed total Hg conc of 0.5 mg/kg
Sediment to Invert BAF	0.48	unitless	Model considered dw to ww conversion or may use X 0.2978
Future Water Concentration	0	mg/L	no water concentration available
Water to Invert BAF	55000	unitless	
Normalized Food Ingestion Rate	0.333	Kg/Kg-bw/d ww	Diet rates from Sample *et al.* 1996 for little brown bat
Percent terrestrial insects	0	%	
Percent infaunal aquatic insects	1	%	These three values must be ≤ 1
Percent epifaunal aquatic insects	0	%	
Normalized Water Intake Rate	0	L/Kg-bw/d	
Area Use Factor	1	unitless	
Seasonal Use Factor	1	unitless	
Incidental Exposures (*e.g on insects*)	0.01	% of food rate	
Body Weight	0.0075	Kg	
Toxicity Reference Value NOAEL	0.32	mg/kg-bw/d	TRVs from Sample et al 1996 (rat) - primary reference Verschuuren et al 1976
Toxicity Reference Value LOAEL?	0.16	mg/kg-bw/d	
Soil to bug burden	0.515355	mg/kg/d	
Sediment to bug burden	0.03609072	mg/kg/d	
Water to bug burden	0	mg/L/d	
Normalized Food dose	0.01201821	mg/kg-bw/d	
Drinking water dose	0	mg/kg-bw/d	
Normalized Food & Water Dose	0.012138392	mg/kg-bw/d	
Hazard Quotient NOAEL	0.0379	unitless	
Hazard Quotient LOAEL	0.0759	unitless	

Σ Weighted (Abiotic Media Concentration X Bioaccumulation Factor) X Food Ingestion Rate/Body Weight X Use Factors = Dose / Toxicity Reference Value = Hazard Quotient

1 ng = 0.001 μg = 0.00001 mg

1.5E-03 = 0.0015

ppm = mg/Kg = μg/g = ng/mg = 1000 ppb

ppb = μg/Kg = ng/g = pg/mg 0.001 ppm

ppt = ng/Kg = pg/g = fg/mg

Indiana bat (*Myotis sodalis*) food exposure pathway risk calculation for Springfield CWLP project (Version 2a)

Chemical: Mercury (total)

Assumptions: **uses total Hg concentration**

100 % infaunal aquatic insects

Future Soil Concentration	0.00063	mg/Kg dw	
Existing Soil Concentration	0.06	mg/Kg dw	
Soil to Invert BAF	8.5	unitless	
Future Sediment Concentration	0.00126	mg/Kg dw	
Existing Sediment Concentration	0.5	mg/Kg dw	
Sediment to Invert BAF	0.48	unitless	Model considered dw to ww conversion or may use X 0.2978
Future Water Concentration	0	mg/L	no water concentration available
Water to Invert BAF	55000	unitless	
Normalized Food Ingestion Rate	0.333	Kg/Kg-bw/d ww	Diet rates from Sample *et al.* 1996 for little brown bat
Percent terrestrial insects	0	%	
Percent infaunal aquatic insects	1	%	These three values must be ≤ 1
Percent epifaunal aquatic insects	0	%	
Normalized Water Intake Rate	0	L/Kg-bw/d	
Area Use Factor	1	unitless	
Seasonal Use Factor	1	unitless	
Incidental Exposures (*e.g on insects*)	0.01	% of food rate	
Body Weight	0.0075	Kg	
Toxicity Reference Value NOAEL	0.32	mg/kg-bw/d	TRVs for methyl mercury from Sample et al 1996 (rat) - primary reference Verschuu
Toxicity Reference Value LOAEL?	0.16	mg/kg-bw/d	
Soil to bug burden	0.515355	mg/kg/d	
Sediment to bug burden	0.2406048	mg/kg/d	
Water to bug burden	0	mg/L/d	
Normalized Food dose	0.080121398	mg/kg-bw/d	
Drinking water dose	0	mg/kg-bw/d	
Normalized Food & Water Dose	0.080922612	mg/kg-bw/d	
Hazard Quotient NOAEL	0.2529	unitless	
Hazard Quotient LOAEL	0.5058	unitless	

Σ Weighted (Abiotic Media Concentration X Bioaccumulation Factor) X Food Ingestion Rate/Body Weight X Use Factors = Dose / Toxicity Reference Value = Hazard Quotient

1 ng = 0.001 μg = 0.00001 mg

1.5E-03 = 0.0015

ppm = mg/Kg = μg/g = ng/mg = 1000 ppb

ppb = μg/Kg = ng/g = pg/mg 0.001 ppm

ppt = ng/Kg = pg/g = fg/mg

Indiana bat (*Myotis sodalis*) food exposure pathway risk calculation for Springfield CWLP project (Version 1b)

Chemical: Mercury (methyl)

Assumption: **15% methylation of sediments**

50% terrestrial & 50% infaunal aquatic

Future Soil Concentration	0.00063	mg/Kg dw	total Hg
Existing Soil Concentration	0.06	mg/Kg dw	total Hg
Soil to Invert BAF	8.5	unitless	
Future Sediment Concentration	0.000189	mg/Kg dw	assume 15% methylation rate for sed total Hg conc of 0.00126 mg/kg
Existing Sediment Concentration	0.075	mg/Kg dw	assume 15% methylation rate for sed total Hg conc of 0.5 mg/kg
Sediment to Invert BAF	0.48	unitless	Model considered dw to ww conversion or may use X 0.2978
Future Water Concentration	0	mg/L	no water concentration available
Water to Invert BAF	0	unitless	
Normalized Food Ingestion Rate	0.333	Kg/Kg-bw/d ww	Diet rates from Sample *et al.* 1996 for little brown bat
Percent terrestrial insects	0.5	%	
Percent infaunal aquatic insects	0.5	%	<u>These three values must be < 1</u>
Percent epifaunal aquatic insects	0	%	
Normalized Water Intake Rate	0	L/Kg-bw/d	
Area Use Factor	1	unitless	
Seasonal Use Factor	1	unitless	
Incidental Exposures (*e.g on insects*)	0.01	% of food rate	
Body Weight	0.0075	Kg	
Toxicity Reference Value NOAEL	0.32	mg/kg-bw/d	TRVs from Sample et al 1996 (rat) - primary reference Verschuuren et al 1976
Toxicity Reference Value LOAEL?	0.16	mg/kg-bw/d	
Soil to bug burden	0.515355	mg/kg/d	
Sediment to bug burden	0.03609072	mg/kg/d	
Water to bug burden	0	mg/L/d	
Normalized Food dose	0.091815712	mg/kg-bw/d	
Drinking water dose	0	mg/kg-bw/d	
Normalized Food & Water Dose	0.09273387	mg/kg-bw/d	
Hazard Quotient NOAEL	0.2898	unitless	
Hazard Quotient LOAEL	0.5796	unitless	

Σ Weighted (Abiotic Media Concentration X Bioaccumulation Factor) X Food Ingestion Rate/Body Weight X Use Factors = Dose / Toxicity Reference Value = Hazard Quotient

1 ng = 0.001 μg = 0.00001 mg

ppm = mg/Kg = μg/g = ng/mg = 1000 ppb

ppb = μg/Kg = ng/g = pg/mg 0.001 ppm

ppt = ng/Kg = pg/g = fg/mg

1.5E-03 = 0.0015

Indiana bat (*Myotis sodalis*) food exposure pathway risk calculation for Springfield CWLP project (Version 2b)
Chemical: Mercury (total)
Assumptions: **uses total Hg concentration**

50% terrestrial and 50% infaunal aquatic insects

Future Soil Concentration	0.00063	mg/Kg dw	
Existing Soil Concentration	0.06	mg/Kg dw	
Soil to Invert BAF	8.5	unitless	
Future Sediment Concentration	0.00126	mg/Kg dw	
Existing Sediment Concentration	0.5	mg/Kg dw	
Sediment to Invert BAF	0.48	unitless	Model considered dw to ww conversion or may use X 0.2978
Future Water Concentration	0	mg/L	no water concentration available
Water to Invert BAF	55000	unitless	
Normalized Food Ingestion Rate	0.333	Kg/Kg-bw/d ww	Diet rates from Sample *et al.* 1996 for little brown bat
Percent terrestrial insects	0.5	%	
Percent infaunal aquatic insects	0.5	%	<u>These three values must be ≤ 1</u>
Percent epifaunal aquatic insects	0	%	
Normalized Water Intake Rate	0	L/Kg-bw/d	
Area Use Factor	1	unitless	
Seasonal Use Factor	1	unitless	
Incidental Exposures (*e.g on insects*)	0.01	% of food rate	
Body Weight	0.0075	Kg	
Toxicity Reference Value NOAEL	0.32	mg/kg-bw/d	TRVs for methyl mercury from Sample et al 1996 (rat) - primary reference Verschuu
Toxicity Reference Value LOAEL?	0.16	mg/kg-bw/d	
Soil to bug burden	0.515355	mg/kg/d	
Sediment to bug burden	0.2406048	mg/kg/d	
Water to bug burden	0	mg/L/d	
Normalized Food dose	0.125867307	mg/kg-bw/d	
Drinking water dose	0	mg/kg-bw/d	
Normalized Food & Water Dose	0.12712598	mg/kg-bw/d	
Hazard Quotient NOAEL	0.3973	unitless	
Hazard Quotient LOAEL	0.7945	unitless	

Σ Weighted (Abiotic Media Concentration X Bioaccumulation Factor) X Food Ingestion Rate/Body Weight X Use Factors = Dose / Toxicity Reference Value = Hazard Quotient

1 ng = 0.001 μg = 0.00001 mg

1.5E-03 = 0.0015

ppm = mg/Kg = μg/g = ng/mg = 1000 ppb

ppb = μg/Kg = ng/g = pg/mg 0.001 ppm

ppt = ng/Kg = pg/g = fg/mg

standard bcc's: official file copy w/attachment(s)
originator's file copy w/attachment(s)
originating organization reading file w/attachment(s)

other bcc's:

ARD:APB:APS: :01/25/05
DISKETTE/FILE:

AIR AND RADIATION DIVISION CONCURRENCE SHEET

SUBJECT: CWLP ESA Analysis

CONTROL NUMBER (if applicable):

	Name	Initials	Date
Typist	( )		
Originator	(Rachel Rineheart)	RR	6/12/06
Reviewer	( )		
Reviewer	( )		
Section Secretary	(I HARRIS)	IH	6/13/06
Section Chief	(P. BLAKLEY)	PB	6/13/06
Branch Secretary	( )		
Branch Chief	( )		
Division Secretary	( )		
Associate Director (if applicable)	( )		
Division Director	( )		

If CONCURRENT SIGNOFF IS NECESSARY, PLEASE INDICATE NAME OF APPROPRIATE DIVISION(S)

NAME OF DIVISION

Assigned Staff Person	( )	
Division Director	( )	
Other	( )	

NAME OF DIVISION

Assigned Staff Person	( )	
Division Director	( )	
Other	( )	

OFFICE OF THE REGIONAL ADMINISTRATOR

Deputy Regional Administrator	( )		
Regional Administrator	( )		
Other	( )		
Other	( )		

The originator and first level supervisor are responsible for assuring that documents are in plain language. All other reviewers should consider plain language in their reviews.
For more information, see the plain language checklist on the reverse side of this sheet.

COMMENTS:

RETURN TO:

EXHIBIT 6

ILLINOIS ENVIRONMENTAL PROTECTION AGENCY

IN RE: PUBLIC HEARING CONCERNING
CONSTRUCTION PERMIT/PSD APPROVAL
TO CITY, WATER, LIGHT & POWER

WEDNESDAY, MARCH 22, 2006
7:00 P.M.
SOUTHEAST HIGH SCHOOL
2350 E. ASH
SPRINGFIELD, ILLINOIS

PATKES REPORTING SERVICE
(217)787-9314

REPORTER: LAUREL A. PATKES, CSR #084-001340

PANEL MEMBERS:

CRYSTAL MYERS-WILKINS, Hearing Officer
SHASHI SHAH
CHRIS ROMAINE

I N D E X

HEARING OFFICER MYERS-WILKINS: Good evening, everyone.

My name is Crystal Myers-Wilkins, and I am an attorney with the Illinois EPA, Environmental Protection Agency.

I want to begin by just thanking everybody for coming out this evening because the EPA recognizes that the public hearings that we have are a crucial part of the permit review process, so we thank you for your interest in this process.

I've been designated by the director

of the EPA to serve this evening as the hearing officer in this matter.

As the hearing officer, my sole purpose tonight is to make sure that these proceedings run properly and according to the rules. It's my job to answer questions regarding the procedure, but it's not my job to answer questions regarding the permit process or the permit itself.

This is an informational public hearing before the Illinois EPA in the matter of a construction permit/PSD approval for the City, Water, Light & Power Company.

The EPA consideration of this permit

5

application involves issues concerning a proposed new boiler to replace two existing coal fired boilers at the CWLP plants.

Under the PSD rules, CWLP must use best available control technology, an acronym that you may hear throughout the evening, BACT, for emissions of CO, PM, and sulfuric acid mist from the new boiler and other new and modified emission units associated with that boiler.

The time now is about 7:13, the date Wednesday, March 22, 2006, and the purpose of this hearing is to field questions and comments on the Illinois EPA's draft permit for CWLP.

This public hearing is being held under the provisions of the Illinois EPA's procedures for permit and closure plan hearings which can be found in 35 Illinois Administrative

Code Part 166, Subpart A.

Copies of these procedures can be obtained from either myself or, upon request, they can also be accessed on the Web site for the Illinois Pollution Control Board at www.ipcb.state.il.us.

An informational public hearing means

that this is strictly an informational hearing. It is an opportunity for the Illinois EPA to provide you with information concerning the permit, and it's also an opportunity for you to provide information to the Illinois EPA concerning that same permit. This is not a contested hearing.

I would like to explain how tonight's hearing is going to proceed.

First we will have the EPA staff introduce themselves and identify the responsibilities at the agency.

Then employees of CWLP will introduce themselves and provide an overview of the project to be permitted.

Following this overview, I will allow the public to ask questions or provide comments. You are not required to verbalize your comments. Written comments are given the same consideration and may be submitted to the agency at any time within the public comment period which ends at midnight April 21, 2006.

Although we will continue to accept

comments through that date, tonight is the only time that we will accept oral comments.

7

Any person who wants to make an oral comment may do so as long as the statements are relevant to the issues that are addressed at the hearing and that they have indicated on their registration card that they would like to comment, so if you have not signed a registration card at this juncture, please feel free to see Brad at the back doors, and he will provide you with that comment card.

If you have lengthy comments or questions, it might be helpful to submit them to me in writing before the close of the comment period, and I will ensure that they are included in the hearing record as exhibits.

Please keep your comments and questions relevant to the issues at hand. If your comments fall outside the scope of this hearing, I may ask you to proceed to another issue that is relevant.

All speakers will have the option of directing questions to the Illinois EPA panel or they can just make general comments or they can do both.

The applicants are also free to

8

answer questions if they are willing to do so but I'm not in a position to require a response this evening.

Our panel members will make every attempt to answer the questions presented but I will not permit the speakers to argue, cross-examine, or engage in a prolonged dialogue with our panel tonight.

For the purpose of allowing everyone to have a chance to comment, I am asking that groups, organizations, and associations keep their questions and comments to approximately 15 minutes and that individuals keep their comments to approximately five minutes in the interest of time and to give everyone who desires to speak that opportunity.

Further, I would like to avoid unnecessary repetition so if anyone before you has already presented the same material that is contained in your written or oral comments, please skip over these issues when you speak.

Remember, all written comments, whether or not you say them aloud, will become part of the official record and will be considered.

After everyone has had an opportunity to speak and provided that time permits, we will allow those who either ran out of time during their initial comments or have additional comments or thoughts to speak.

There are some registration cards on the table. Again, if you have not filled one out, please do so.

Anyone who fills out one of the cards will also receive a letter announcing the Illinois EPA's decision. That letter will also direct you to the Web site where you can retrieve all the details including the agency's responsiveness summary.

The agency's responsiveness summary will attempt to answer all the relevant questions raised at this hearing or submitted to me prior to the close of the comment period.

The responsiveness summary, the transcript, and the final permit will all be available online or you can sign up to receive a mailed copy.

Printed copies of these documents will also be available at one or more local libraries.

The written record in this matter will close again April 21st, midnight, 2006. Therefore, I would accept all written comments as long as they are postmarked by midnight on that date.

During the comment period, all relevant comments, documents or data will also be placed into the hearing record as exhibits.

Please send all written documents or data to my attention at the following address: Crystal Myers-Wilkins, Hearing Officer, Illinois Environmental Protection Agency, 1021 North Grand Avenue East, Post Office Box 19276, Springfield, Illinois, zip 62794.

This address was also listed on the public notice for this hearing this evening.

For those who will be making comments or asking questions this evening, I want to remind you that we do have a court reporter making a verbatim record of these proceedings for the purpose of creating an administrative record.

For her benefit, please keep the general background noise level in this room to a minimum so that she can hear and properly record

everything said, and let's show respect for the individual who has the floor.

Also, please keep in mind that any comments from those other than the person at the microphone will not be recorded by the court reporter and will simply be a disruption of this process.

This rule applies not only when audience members are speaking but also when the panel from the Illinois EPA is speaking.

When it's your turn to speak, please speak clearly, slowly, and into the microphone so that the court reporter can understand what you are saying.

When you begin to speak, state your name and, if applicable, any governmental body, organization or association that you represent.

For the benefit of the court

reporter, we ask that you spell your last name. People who have requested to speak will be called upon in the order in which they've registered to make a statement.

Now, unless I've missed something regarding preliminary information, we will begin

with introductions from the Illinois EPA panel, and that will be followed by introductions from CWLP, and that will be followed by comments.

MR. ROMAINE: Good evening. My name is Chris Romaine. I'm manager of the Construction Permit Unit in the Air Permit Section.

I don't have that much to say in terms of introductory remarks. I simply want to welcome everybody for coming tonight. Your presence is what makes this hearing productive. We look forward to hearing your comments and your questions.

And I also want to let you know that I have taken advantage of tonight's hearing -- we have a number of members of the staff of the Air Permit Section here tonight in addition to Brad Frost who welcomed you, so I have taken advantage of tonight's hearing, because it is in Springfield, as an opportunity to remind people in the Permit Section that even though we issue permits to sources of pollution, we process applications, issue permits for these sources, we actually work for the public, and there's nothing like a public hearing to remind people who we actually work for.

So that's why you're here. Bruce,

George, Bob, Bob, Kevin, Minesh, Jason, Mike, Mike, and German.

Why don't you just stand up so people can recognize you if they have questions later on.

With that, I will turn over the microphone to you, Shashi.

MR. SHAH: My name is Shashi Shah, and I work in the Bureau of Air in the Permit Section.

Good evening, ladies and gentlemen. My name is Shashi Shah. I am a permit engineer in the Bureau of Air, Permit Section.

I'd like to give you a brief description of the project being discussed tonight.

City, Water, Light & Power, abbreviated CWLP, has requested an air pollution control permit from the Illinois Environmental Protection Agency to construct a new coal-fired boiler, Dallman Unit 4, at its existing power plant adjacent to Lake Springfield located at 3100 Stevenson Drive in Springfield.

The new boiler would serve a new generator with a nominal capacity of 250-megawatts.

The proposed new boiler would replace

two existing coal-fired boilers at the plant, Lakeside Units 7 and 8.

The emissions of the new boiler would

be controlled by a number of devices and techniques. Low NOx combustion technology and selective catalytic reduction would be used for control of nitrogen oxide emissions. A scrubber would be used for control of sulfur dioxide emissions. For carbon monoxide, the new boiler would use good combustion practices.

For particulate matter, the boiler would be equipped with a fabric filter or a baghouse and a wet electrostatic precipitator.

For sulfuric acid mist, control would be provided by the combination of the scrubber and the wet electrostatic precipitator.

The new boiler would be subject to and have to comply with emission standards for new utility boilers under the federal New Source Performance Standards.

This project is not considered a major project for emissions of sulfur dioxide and nitrogen oxide. This is due to the measures and control equipment being used for nitrogen oxide and

for sulfur dioxide emissions.

As a result, the project will result in a net decrease in emissions of nitrogen oxides and sulfur dioxide after considering the actual decrease in emissions that will occur from the shutdown of the two existing Lakeside units.

The proposed project would be a major project for emissions of carbon monoxide, particulate matter, and sulfuric acid mist because the permitted emissions of these pollutants would be greater than significant emission thresholds.

For these pollutants, the proposed project must use best available control technology. The Illinois EPA has determined that the control measures being used on the boiler for carbon monoxide, particulate matters, and sulfuric mist will provide best available control technology.

Other units that are part of the project would also use appropriate work practices, control devices, and equipment design for control of particulate matter emissions.

Illinois EPA's initial review concludes that these proposed measures would provide best available control technology.

CWLP submitted air quality analyses for the proposed project. These analyses show that the proposed project would not violate national ambient air quality standards or prevention of significant deterioration increments.

National ambient air quality standards are the standards for pollutant concentration in the air established by USEPA to be protective of public health and welfare.

Increments are additional standards under the prevention of significant deterioration rules that protect air quality from significant deterioration.

The analyses show that the proposed

project would not have significant impacts for carbon monoxide.

For particulate matter, the analyses show that the proposed project would not cause violations of the national ambient air quality standards or the increments.

In summary, the agency has reviewed the application submitted by CWLP and has determined that it complies with applicable state and federal standards.

The agency has prepared a draft of a construction permit that sets out the conditions that we propose to place on the proposed project.

In particular, continuous sulfur dioxide, nitrogen oxide, and opacity monitors would be installed in the stack of the boiler.

As a power plant, these monitors must be operated in accordance with the protocols of the Federal Acid Rain Program.

The permit would also require continuous monitoring for particulate matter as a compliance assurance method.

In closing, the agency is proposing to grant a construction permit for the proposed project, and we welcome any comments from the public.

HEARING OFFICER MYERS-WILKINS: Before we take comments from the public, we will allow CWLP to give a basic overview of the project.

MR. MURRAY: Thank you, Madame

Hearing Officer.

My name is William Murray, and I'm a regulatory affairs manager for the City of Springfield, City, Water, Light & Power.

I'd like to start by introducing the rest of our project team that's here tonight that's been working on this project from initial conceptions to permit application and then working with the agency.

First, Jay Bartlett, our chief utility engineer. Jay is in actual charge of all electric department operations.

Brian Fitzgerald is the project manager. He's an engineer. He's our lead project engineer on this team.

Next to Jay we have Mary Hanauer who is with Burns McDonnell. She was instrumental in putting our permit application together and coordinating all the modeling that needed to be done.

We have Dave Farris who is our environmental health and safety manager, and PJ Becker next to him who's with our environmental staff.

We've got another one around here somewhere, Sky Wilmore -- there he is -- who is also with our environmental staff.

I'd like to thank all of them for the

work that they've contributed to this project.

I'd also like to welcome you all here. I'm going to give a little overview of what City, Water, Light & Power does and kind of a description of our generating capabilities. I think that's important for those of you that are from out of town and not familiar with us from a day-to-day standpoint.

We have been in the retail electric business since about 1917. We currently have a service area of about 70 square miles. That would take in the city limits of Springfield, the villages of Jerome, Southern View, and City of Leland Grove.

We also serve an unincorporated area south of the city between the city proper and Lake Springfield. We serve unincorporated areas adjacent to the lake on the south side of the lake.

That service territory comprises about 134,000 people. We have about 69,000 retail electric customers, actually a little over that.

We also are the full requirements supplier to the Villages of Chatham and Riverton who operate their own distribution system for electric purposes in the same manner we do.

We employ slightly over 700 people in our operations here in Springfield.

As I said, we've been in the business for quite some time, and actually, the city started out with an electrical plant on the Sangamon River in the early 1900s providing street lighting and electricity to city facilities before it got into the retail business.

We also operated a water plant at that site, and as the city grew, the capacity and the water quality from that location came into question, and the city fathers embarked on a project to construct Lake Springfield, and in connection with that project, they conceived a power plant site at the lake which is now 3100 Stevenson Drive.

It was sort of a rural area at that time remote from the city, but that is where they constructed the Lakeside plant and that plant eventually went on to house eight boilers and seven turbines.

Now, today, the Lakeside plant only consists of Boilers 7 and 8. Those two units are each approximately 38 megawatts and came on line commercially in 1958 and 1962 respectively.

We have a Dallman plant that sits south of the Lakeside plant. Dallman 1 and 2 are each about 86 megawatts, and they came on line in 1968 and 1972 respectively.

Dallman 3, which is what we call our newest unit, actually came on line in 1978, and so it's approaching 30 years in age.

The scrubber that serves that unit actually was not completed until 1980. It was sort of a retrofit project that kind of lagged the initial construction plant.

That's our coal fleet. We haven't put any new ones in since that on the coal side.

With regard to control equipment on that side, Lakeside only has particulate control for electric with electrostatic precipitator, and Unit 7 has some degree of NOx control with some over fire air that we added in a clean coal technology project back in the late 1980s.

The Dallman Units 1 and 2 were equipped with a scrubber in 2001 for SO2 control and were then equipped two, well, three years ago, two years running now with selective catalytic reduction systems for NOx control.

Dallman 3 of course has the scrubber, and it has the SCR system for NOx control installed at the same time.

The precipitators on all these units, the scrubbers and the NOx control equipment also serve to control to some degree mercury emissions from each of those plants.

In 1997, we added a combustion turbine at Interstate. This is our most recent unit. It's 128 megawatts, and it runs on fuel oil and natural gas.

We had two smaller turbines that were installed in the 1970s, the factory turbine in 1973 which was 21 megawatts, it's diesel-fired, and the Reynolds combustion turbine in 1970 which is 17 megawatts, also diesel-fired.

All our coal units and Interstate are part of the acid rain program. It's a CAAPP and trade program governing SO2 allowances, so we have a compliance program that involves requiring you to hold allowances equal to your emissions.

All our coal units, Interstate and the factory gas turbine, are also subject to the Nox SIP call program which is an ozone season program

that runs from May 1st to September 30th, and we have to have allowances equal to our emissions on those units for those programs.

Now, the coal supply for our units all comes from the Viper coal mine in Elkhart, Illinois which is about 23 miles up the Interstate from the power plant site.

All our coal is washed. All our coal is delivered by truck. We have no capabilities at the site to take unit trains which is typically what you would take delivery on from western coal or bottom river basin coal or low sulfur coal, whatever you want to refer to it.

We also, of course, are not served by any waterway system that would allow barged coal.

We also do not have room to expand at our site that would allow delivery of coal, so our fuel supply is very limited.

Our contract also gives the mine the right to supply any new units that replace existing units that were in effect at the time the contract was entered into in 1980.

In terms of our utilization, our Lakeside units probably use about 10 to 15 percent

of our coal supply in a year. We range from 1.1 million to 1.2 million tons of coal utilization a year.

Our Dallman 3 unit is about 550,000 tons, and the remaining coal is used at Dallman Units 1 and 2.

We also have a program where we combust expired seed corn at our cyclone units which would be the Lakeside units or Dallman 1 and 2. We do that in the non-ozone season because the seeds could affect the catalyst in the SCR in the combustion process.

I'd like to talk a little bit about unit dispatch. That's when units are turned on and turned off.

There's various considerations that we go through in determining when to run units. They depend upon unit efficiencies and economics and unit size, load and customer demand which is also weather-related. Whether it's going to be hot or cold usually means whether or not we're going to have greater demand on our resources.

Emission costs from those CAAPP and trade allowance programs are also considered. This

is particularly so with regard to the Lakeside units which has no controls for SO2 and very little control for NOx emissions.

Another thing that you have to realize in the dispatch consideration is that units don't run at full loads 24 hours a day seven days a week. They don't run when they're on at full load all the time. They run less at night and more during the day, so these are all considerations that you have to have when you dispatch.

Now, our typical dispatch order would be Dallman 3 first, that's our base load unit, followed by the two other Dallman units, the Lakeside units, and then the combustion turbines depending upon fuel cost and other factors and when they would come on on a particular day, but that's the typical dispatch order for our system.

I'd like to talk now a little bit more about the Dallman 4 project as it was alluded to by the agency.

One element in this project is retirement of Lakeside 7 and 8. Again, these are uncontrolled units for the most part in terms of the major pollutants that we have to consider with

existing clean air requirements and the requirements that we know are coming down the road; most specifically, the mercury rules, whether it be the federal rule or the proposed state rule, and the CAIR rule which is going to require further reductions of NOx both on an annual basis and an ozone season basis starting in 2009 and further reductions of SO2 starting in 2010 and actually down even further on both of those pollutants in 2015.

So we are faced with this decision of what to do with the Lakeside units, and the logical conclusion that we came to from a technical and economical standpoint, the age of the units, they're going to be 50 years old soon, was that they retire them.

That gave us another planning point. We need to make some decision about replacing that amount of generation.

We've spent a number of years, we probably started around the turn of the century right after we got Y2K put to bed, on planning for what we're here for tonight.

Some of the things that we considered initially in our planning is, of course, the age of

all our other units. As I said before, our newest coal unit came on line in 1978. It's not a new unit by any stretch of the imagination.

We also had to consider our load growth, both historical and what we projected out for the next 15 years, at least from our planning horizon.

We also had to look at factors of whether we wanted to import electricity from sources remote to Springfield and examine the transmission risks and the issues in that type of consideration.

We also had to consider sites where

you might build new generation.

In looking at all these general things, we concluded that it was most feasible for us to add base load generation.

What base load generation is, we needed to look at putting in a plant that would be our first dispatched unit, our most efficient and our cleanest. It would run most of the time and hopefully serve the needs that we needed to have addressed based on our analysis.

What we then embarked on, we hired a consultant to do a study to see whether our existing

plant site could accommodate new generation, and by doing that, they looked at footprints for different technologies and also examined the transmission export capability that we had from that site.

We received a satisfactory conclusion from that study, and all these studies were presented to the utilities committee, the city council. All the contracts to hire these firms to do the studies were discussed in city council meetings and in utility meetings and were addressed in the media throughout this process.

Once we had determined that we could fit a plant at our site, we then hired another consultant, another engineering firm, Black & Veatch, to do an analysis of generation alternatives that could be utilized at that site.

We reviewed and they reviewed

different technologies including IGCC, pulverized coal, fluidized bed coal plant, gas combustions or combined cycle combustion technology, and different unit sizes, 200 megawatts, 300 megawatts, and then also did technical and economic cost feasibility studies regarding the different technologies.

We also analyzed on site and off site

locations. We looked at partnering in other announced or projected projects that were going around the state.

Also during this time we had visits with several or a couple of the developers that were proposing wind projects and took all this under our advisement in terms of coming up with a recommendation for the city council.

That recommendation turned out to be Dallman 4, the project we're here discussing tonight.

The report recommended that the best option for the city was a pulverized unit at our existing generating station.

The biggest issue that actually was discussed politically and in public when this decision came out was whether it should be a 300-megawatt plant or a 200-megawatt plant.

While our permit application is for 250-megawatt plant, the technology that we are actual settling on is a 200-megawatt unit.

HEARING OFFICER MYERS-WILKINS: Mr. Murray, if you can begin wrapping up.

MR. MURRAY: Okay. Shashi has

30

actually done most of the remaining part, but I would like to point out that this plant will have no thermal discharge at Lake Springfield. It's going to be served by a cooling tower, and that coupled with the retirement of Lakeside would reduce the heat loading to the lake. We think that's a very beneficial point of this project.

We're also going to have a dry ash handling system for this project. They're going to have a spray dryer absorber system to handle various wastewater streams from this plant and the other Dallman units.

We're going to use existing coal delivery system, limestone delivery and handling system, and we're going to have a new synthetic handling system for all the Dallman units.

Our project schedule is to be done in June of 2009, at least for initial startup and running of the unit.

This is very important to us because of all the air regulations that are supposed to kick in at that time and will enable us to remain in compliance very easily with all those regulations. That would be mercury and the NOx in 2009 and the

31

SO2 requirements in 2010.

Dallman 4 will be our base load unit.

This will reduce the utilization of the other Dallman units.

The total emissions from these plants will be less than actually is projected in our application.

The analysis that is done for BACT assumes that the new unit runs at maximum load all the time and of course that's not going to be the case, so the emission reductions are going to be greater.

Project delays would be very significant for us both in the terms of cost and in terms of our ability to adequately and safely meet the compliance standards that we need to do starting in 2009.

HEARING OFFICER MYERS-WILKINS: Thank you.

Diane Hughes?

Could you please state your first and last name and spell your last name and who you're affiliated with?

MS. HUGHES: My name is Diane Lopez

Hughes (H-u-g-h-e-s), and I am a member of the Sierra Club in Springfield, the Sangamon Valley Group. I'm also a community member. I'm a registered nurse, and I've worked as a nurse for over 15 years. Before I worked, I was raising my kids so I was at home.

As a professional community member, I'm very concerned about those in our community who have asthma, heart disease, and other respiratory conditions.

While I understand that this plant will be a cleaner plant, a much cleaner plant, coal burning power plants are not clean by definition. There is technology out there that can be used to supplement coal burning power plants, reduce the emissions, and still provide safe and clean energy, so that's kind of what my focus is.

I'm very concerned about health. A great percentage of the terminally ill patients that I've worked with -- I've worked in hospice over the past seven years -- have had lung cancer. Lung cancer is the most prevalent form of cancer that we see. Most of our patients, a good percentage of them had either lung cancer or other end stage

33

respiratory illness.

I've seen people when they've been struggling to catch their breath and fear that they're going to die from suffocation. It's a very unpleasant disease in its later stages. I've seen people who have asthma, who have difficulty, need to go to the emergency room, not only adults but children, and how they handle that kind of illness. School time missed. People with respiratory illness miss work time. People with lung cancer and people with other heart lung diseases that are affected by the quality of the air we breathe also miss work time.

I guess I also want to say that people are concerned about this particular matter and its effect on global warming. Two weeks ago I was in a faith-based conference on global warning among other issues, and one of the facts that was pointed out is that if we don't control global warming, by the end of the century, our climate and agricultural atmosphere I guess you could say will be the same as what we find in east Texas right now, and you know that corn doesn't grow in east Texas, and the other things that are planted in central

Illinois can't grow in that kind of environment.

I think for the health of our children and for the health of those in the future, we really need to look at this particular power plant and how we conduct it.

I also am concerned that there may be people who aren't here tonight because they thought that this was all decided.

It isn't decided. There are a number of things that needs to take place before the permit is approved, so I hope that those who care about our environment will let others know that they can write to the EPA and share their concerns.

Thanks very much.

HEARING OFFICER MYERS-WILKINS: Thank you.

Becky Clayborn?

MS. CLAYBORN: Thank you for having this public hearing tonight. I really appreciate it.

My name is Becky Clayborn (C-l-a-y-b-o-r-n). I'm a regional representative with the Sierra Club.

This is a perfect example, as Chris

was saying earlier, of the public process which is exactly what our communities and our democracy is built upon, and I've mentioned to the CWLP guys before, we can have different opinions and still sit in a room and hear each other's opinions, and I'm really happy that the IEPA has these opportunities for the public to come out and express their opinions about such an important, really important issue.

As I said, I'm a regional representative with the Sierra Club. We represent about 25,000 members in the State of Illinois, and we oppose this project as presently proposed and ask that the IEPA deny all such permits for new coal-fired power plants that are using old dirty technology.

We're seeing across the Midwest a rush of new coal-fired power plants being proposed, 130 across the entire United States, over half of them in the upper Midwest, and 15 of them, the most of any state, are being proposed here in Illinois. That's not power for us for the most part. It's power that's being produced here and we get to keep the pollution.

Unfortunately, CWLP is being critiqued by Sierra Club because every time one of these new coal-fired power plants is built, is permitted, we're setting a precedent for the next new coal-fired power plant.

These coal-fired power plants for the most part are not clean. They're not using the state of the art technology that they could be using. Gasification is a really new but really exciting possibility for coal that has a lot less emissions from burning the coal, but we believe that Springfield can be an example, can be a leader in this state for a cleaner energy future for Illinois but not with a new coal-fired power plant using older technology that's three times the size of the power plant that they're shutting down.

The Lakeside plant is about 75 megawatts and the new plant is going to be about 200 megawatts, and there will be more pollution. Even though it's a cleaner, newer plant, it's three times the size of the old plant, so there will be more pollution added to the atmosphere.

One of the pollutants that we're concerned about is the particulate matter that's

going to be coming out of the plant. There's going to be 500 tons per year added to the atmosphere, more than what we're already experiencing here in Springfield with the Lakeside plant.

That's really a concern for us because according to American Lung Association, in the county, there's already 14,000 people suffering from asthma. Those people are going to be affected even more so by the particulate matter that's coming out of this power plant, the additional particulate matter.

In Illinois, there's a million people with asthma. I'm sure every person in here knows somebody, either a family member or a friend, that suffers from asthma, and it's not fun, and the numbers are rising, and these are the kind of issues that can aggravate asthma.

The 2005 data from the USEPA shows that Sangamon County actually didn't meet the EPA air quality standards for PM 2.5.

This is a number that the EPA sets, USEPA sets, to show, okay, you can't go over this number and still have a healthy community.

Sangamon County went over that number

38

in 2005 for particulate matter, the really, really small particulate matter that causes heart attacks, causes lung disease, causes asthma and causes death.

We shouldn't be adding to the particulate matter in the area if we already can't meet the particulate matter standards in Sangamon County. If anything, we should be decreasing the PM emissions.

I was wondering if the EPA could

comment on that.

Have you come across this before? How do you handle this issue if they're not in compliance or haven't met the standard for the past year?

MR. ROMAINE: Well, as we've set forth in the project summary, Sangamon County is in compliance with the PM 2.5 air quality standard. Compliance with the ambient air quality standard is determined on a three-year average, and for the three-year average, we're about ten percent below the ambient air quality standard, so Sangamon County is in compliance.

MS. CLAYBORN: I understand that, but last year, just the data for 2005, the number for PM

2.5 was above the standard.

MR. ROMAINE: It wasn't, because the standard -- PM 2.5 is original pollutant. It varies from year to year based on the weather, the amount of energy demands, a variety of factors.

When USEPA went through its process of evaluating the appropriate forum to set the ambient air quality standard, it established a standard in which it was appropriate to look at an average of annual data, not simply a single year's worth of data.

MS. CLAYBORN: Yeah, I understand that, but I guess if we're seeing a trend and increase in PM 2.5, even if it hasn't for the past three years gone over, I think it's notable that the numbers are going up and it was over the standard for last year.

MR. ROMAINE: I guess our position is there are a number of programs going into effect that have been alluded to including the Clean Air Interstate Rule that are going to have drastic effects on reducing emissions of precursor compounds that contribute to formation of PM 2.5.

We are working strenuously to come up

with an attainment strategy that will bring places like the urban core in the Chicago area into attainment. Those measures will also have secondary benefits for places like Springfield which are much less urbanized than Chicago or St. Louis.

MS. CLAYBORN: Thank you.

We still have a concern with that, and actually, I would urge the EPA to have some sort of a standard in place for when an area is getting close to, I mean, this is really close to crossing that line, and is it really appropriate to be adding 500 tons of total PM to an area if it's not meeting the standard.

That's all. I would just urge the IEPA to address that.

MR. ROMAINE: I guess my other simple answer is that this program results in an overall decrease in precursors to PM 2.5. The sulfur dioxide emissions are being reduced by over 5,000 tons which is ten times the increase that theoretically would occur using this worst case arithmetic that's used to evaluate what the change in emissions is.

As Mr. Murray has explained, we

didn't take into account the fact that this new unit will likely result in reduced utilization of the existing Dallman units. We took the simple evaluation and said what has actually been emitted from the Lakeside units, what will be there no more, what are we permitting this new unit for, assuming it operates continuously, and that's the type of arithmetic that shows the 500 ton increase.

The actual increase for particulate matter could be substantially less than that, and as I said, the arithmetic that was used to evaluate the change in SO2 emissions is a definite.

If, in fact, this unit operates less, we will have, 5,500, 6,000 tons, even more reductions in sulfur dioxide emissions.

MS. CLAYBORN: Well, and I'd like to point out that in terms of the netting exercise in general, Sierra Club doesn't see that as an appropriate way to determine what type of emissions should come out of this new plant because this plant, the Lakeside unit, would have to be shut down or be brought up to compliance.

That plant has been there for 50 years and has had a free ride, has not had to comply with the majority of the new clean air standards. It's has had a free ride.

So the fact that it has to be shut down, they're not shutting it down out of the goodness of their heart. They're shutting it down because these new regulations that are coming into play in 2009 and 2010 are going to make them either clean the plant up or shut it down.

They've decided to shut it down because it costs too much to clean it up I'm assuming.

However, this new plant needs to be, the emissions from this new plant need to be determined on what this new plant is emitting, not determined by how much they're going to be getting rid of with the old Lakeside plant.

And I know that that's not how the law works, but we are saying, Sierra Club is saying that we think that that's not the right way to do business when an old plant is going to have to shut down regardless of building this new plant.

Which brings me to another point which is we heard Mr. Murray talk about what type of options they looked at, and I heard coal, coal,

coal, and coal. Oh, wait. We did talk to some wind people. I did hear that too.

We're concerned that building a plant three times the size of the one that's being shut down is really over relying on coal for

Springfield's power.

The State of Illinois is CWLP's biggest customer. The State of Illinois is striving to have a renewable energy portfolio standard put into place throughout the state that would be eight percent. Eight percent of all energy would have to come from a renewable source.

The State of Illinois buildings here, the IEPA building in Springfield, they can't buy renewable energy because CWLP doesn't have that as an option.

I'm sure that being an environmental organization that you guys would want to be able to buy renewable energy from your energy provider which brings me to the fact that 400 megawatts of wind is being produced or being put into place just up the road in Bloomington. It's a wind farm that's going to be built and up and running by 2007.

That's a really good opportunity.

The citizens of Springfield really have this opportunity to get the municipal utility to invest in this cleaner type of energy, and I'm not saying that I would want all of the energy coming from wind. I know that's not possible. However, it doesn't all have to come from coal.

And I'll just point out again, because you guys are listening now, I think IEPA would like to buy some of their power from a renewable source, and you can't right now because CWLP doesn't have any renewables.

Good. They heard it that time.
HEARING OFFICER MYERS-WILKINS: Ms. Clayborn, if you can begin wrapping up.
MS. CLAYBORN: Yes.
One last thing that I wanted to bring up about the netting exercise is that the numbers that were used by CWLP was the 2002-2003 numbers. That was the data being used for their netting exercises, and it's our belief that when you use the 2004-2005 more current data, that NOx numbers will actually increase, where CWLP using the 2002-2003 numbers showed that it would decrease.
If the NOx numbers increase, then that

means they would have to have a BACT determination for NOx is my understanding.
MR. ROMAINE: As a legal matter, that isn't correct.
As a practical matter, that is a very reasonable position for you to take.
MS. CLAYBORN: Why as a legal matter? I thought they had to use the two years prior to construction?
MR. ROMAINE: In fact, under the federal prevention of significant deterioration rules, a source can go back longer than that.
MS. CLAYBORN: Will you address that in the responsiveness summary?
MR. ROMAINE: Yes, I will thank.
MS. CLAYBORN: Thank you.

And actually, we ask that in the name of air quality for Illinois that you require the most recent data, 2004-2005, to be used in determining whether the emissions go up or down for NOx since there is a discrepancy.

And finally, my last comment, this permit does not address at all global warming emissions which I understand by law it doesn't have

to right now, but the proposed plant, if it's built, would be the largest new source of global warming emissions in this state. It has no opportunity to control or mitigate its global warming emissions, and there should be a serious concern by the taxpayers, by the ratepayers that in the future, global warming emissions are going to be regulated, and at some point, you're going to have to pay for how much global warming emissions you're putting into the air, so your rates are going to go up.

In the interest of time, I will stop, but I do ask that when we go back around that I can come back up.

Thank you.

HEARING OFFICER MYERS-WILKINS: Thank you.

Roger Ricketts?

MR. RICKETTS: Yes. My name is Roger Ricketts (R-i-c-k-e-t-t-s). I am a member of the Sierra Club here in Springfield and live here in Springfield.

My concern is efficiency.

We do have a very effective agency that produces electrical power that's as clean as

they can make it and markets it at a good rate to the city residents of Springfield, but we don't have a company here. We have a part of the city government, and I think their responsibility is not to produce energy efficiently and sell as much as of it they can to the residents. Their responsibility as part of the city government is to reduce the citizens expenditure for power.

And I think we've missed on the issue of efficiency. It doesn't seem to have been addressed whether efficiency could meet some of these needs.

In other jurisdictions such as Wisconsin or California, they have to establish that conservation efficiency will not meet the needs. Here that's glossed over.

That's okay maybe for a private utility but here we have part of the city government glossing over what efficiency can do.

If you spend $200 for electricity, that money is gone forever. If you spend $200 for insulation, you have that money.

I have a house that's old, and I'm sure I have insulation that's 50 or 70 years old. I

have paper in my walls that they put in to save energy.

CWLP has an office which does some of those activities but not anywhere near what could be done. Why is that not part of the evaluation for what the city, part of the City of Springfield is doing for its citizens.

I think there's a lot of other things that could be done that we're not looking at.

Why are they not making loans to consumers so that we could put solar panels or our roof or wind turbines? Why don't they have meters that could run backwards so we get credit for power that we produce in our house? Why don't they have night metering so we could wash clothes at night and save money and use up some of the electricity that they recognize as being generated without a source?

These are things that should be done for the citizens of Springfield because this is our utility.

In many communities, it's been shown that efficiency planning can reduce consumption by ten percent.

Again, we're planning a power company

that we have no plans for efficiency.

If we were all using the better, more efficient light bulbs, how much electricity could we save? I'm not sure we could ever get everybody but what if we increased it by ten percent.

The fact that there's been no planning for these kinds of issues by a city department that's supposed to be protecting us as residents of the City of Springfield, that's the part that's discouraging.

We talked about jobs. It's very clear that we'd have more jobs in Springfield retrofitting houses than we will by digging lots of coal and burning it very quickly.

Why can't we look when we talk about jobs, which we hear about from the coal association all the time, but nobody is there to say retrofitting is a source of jobs as well.

We need to think about the people who need jobs in Springfield who could be employed doing these kinds of things and save energy long term and save them money long term and protect the environment.

Why can't there be co-generation with

the State of Illinois. The State of Illinois has a power plant that produces heat for some of the state buildings. Why can't that also produce electricity.

Why can't we have better street lighting or at least discuss that possibility as meeting our needs.

Why can't we have some renewables. We have no renewables. I mean, the City of Chicago is close, I don't know if they'll get there but they're close to producing eight percent renewables. We as a city utility are producing no renewables.

I don't know how we as a city can let

that go on.

Much of what we need could have been produced as part of this project. We have no per capita utilization that I can find on the Web of what's going to happen in the next 20 years, what they project is happening. They may have it in their files but why can't that be made available to the consumers.

There's much more information, and if this was planned in a comprehensive way at meeting the needs of the citizens of Springfield and becoming an efficient power company producing power

efficiently, then we'd be much better off as citizens of Springfield.

Thank you.

HEARING OFFICER MYERS-WILKINS: Thank you.

David Gurnsey?

MR. GURNSEY: My name is David Gurnsey (G-u-r-n-s-e-y). I am a citizen of Springfield. I am a ratepayer for CWLP. I'm a union rep for the IBEW.

We represent about 400 construction workers and about 160 utility workers in Springfield and the surrounding area.

This plant needs to move forward. As a ratepayer, I applaud CWLP management for planning for the future to secure our energy needs as the market grows.

The way electricity is transmitted

now with deregulation, there's no guarantee that a small municipal utility like CWLP will be able to buy efficiently through the marketplace when the needs are high and plants are down for maintenance or whatever. It happened in California a few years ago. It could happen here.

This plant guarantees that citizens of Springfield and the ratepayers of CWLP will have affordable and as clean as possible commercial electricity.

Some of the technologies that Ms. Clayborn has alluded to are not commercially proven. As a ratepayer, everyone knows where their natural gas bills were this winter. I cannot afford and many people in Springfield could not afford to risk a technology that's not proven commercially.

This is the best thing for the citizens of Springfield. I urge the EPA to expeditiously approve this permit so we can get the dirty power plants at Lakeside shut down and this new one online.

Thank you.

HEARING OFFICER MYERS-WILKINS: Thank you.

David Burns?

MR. BURNS: Hello. My name is David Burns (B-u-r-n-s). I'm the business manager of International Brotherhood of Electrical Workers Local Union 193 here in Springfield.

I'm here tonight to urge the Illinois

EPA to push forward with this project. We think it's good for the city.

Springfield and its citizens are in a unique situation. For years, and like they were saying tonight, since 1917, they've had their own utility, and from the days of when you get Edison and you get those folks putting things together, technology is advanced.

I believe strongly that Jay Bartlett and his crew have put together a powerhouse that will utilize the latest technology to make this thing as clean as possible, and the citizens of this town that own the utility will have the lowest rates because, as my assistant David Gurnsey just said, there's no guarantee out there in the long run. This way, the citizens have got control of what's going to take place with their electrical cost.

It also will provide jobs that are needed throughout, and we urge you strongly to move forward with this.

Thank you.

HEARING OFFICER MYERS-WILKINS: Thank you, sir.

Gary Shepherd?

MR. SHEPHERD: I'm Gary Shepherd (S-h-e-p-h-e-r-d). I'm also a member of Local 193 in Springfield, right now an unemployed member of

Local 193 in Springfield.

This power plant will bring a lot of jobs to this area not only for me but a lot of these young guys sitting over here and their families.

I know I love the air I breathe and the environment. That's all a good concern, and I'm anxious to see a lot of these new technologies take place, but right now, this power plant is needed.

I don't know how much of that 200 megawatts is actually going to be used at one time. I don't think it's probably all going to be, the total capacity, once that 75 watter is shut down, but I'm sure it's not going to be running full bore all the time.

My brother lives at the lake. We go fishing out by his house all the time. Right now with the dirty plant that's there, I don't really notice what's going on. I know that it's in the air, but I've lived here all my life and I don't have any heart problems. My mom is 85 years old.

She's doing well also.

I urge the city to continue with their project.

HEARING OFFICER MYERS-WILKINS: Thank you.

Phil Gonet?

MR. GONET: Hi. My name is Phil Gonet. I'm the president of the Illinois Coal

Association. Gonet is G-o-n-e-t.

On behalf of the Illinois Coal Association, I am here this evening to support the plan of City, Water, Light & Power to construct a 200-megawatt power plant at its Dallman site in Springfield.

CWLP is to be commended for its continued commitment to Illinois coal, one of the state's most abundant resources.

CWLP has proven that emission control systems can be economically installed and operated to burn Illinois coal and meet or exceed federal clean air standards.

Today, residents of Springfield enjoy the lowest electric rates in the state while sulfur dioxide and nitrogen oxide emissions have been

56

reduced beyond required levels.

Moreover, these efforts mean that hundreds of direct coal mining jobs and thousands of spinoff jobs will stay right here in Illinois.

The proposed Dallman 4 power plant will replace two Lakeside units that will be retired. These units are too small and too old to install the necessary pollution control equipment to meet federal emission requirements. Therefore, the new plant will cause a significant decrease in sulfur dioxide and nitrogen oxides in Springfield.

Electric restructuring nationwide has brought unprecedented price volatility to wholesale power markets. Experience has shown that being a bit long on capacity during peak periods is far more prudent than being short. The timing of the new project is critical for the future energy security for the City of Springfield.

Speaking of timing, I would like to point out that this hearing is taking place 16 months after City, Water, Light & Power filed its application for this construction permit. It is unfortunate that this project has been delayed since it will result in drastically reduced levels of SO2

and NOx emissions.

Also, this delay now makes it nearly impossible for CWLP to meet the new clean air standards by 2010. This is going to end up costing our ratepayers -- and I happen to be one here in Springfield -- more money as well in rates.

Residents of Springfield have been accustomed to getting reliable energy at very low costs from City, Water, Light & Power in the past. In fact, our residents have been used to some excellent service, and I think for those of you that are out of town, you might be surprised what this side of town looked like just a week ago, and it's to the men and woman, many of them here in this room, that we're here because they restored power after two very terrible and powerful tornadoes ripped through our town, and I want to thank you guys and women for doing the job. Thanks.

(Applause)

MR. GONET: But that's a service that we've come to expect here in Springfield.

This new project will assure the city's energy independence at reasonable prices for the next half century. Moreover, the project will

result in cleaner air as emissions from current levels will be reduced and all federal air standards will be met .

I urge the Illinois EPA to issue the final construction permit for the Dallman 4 power plant so this important project can move forward.

Thank you for the opportunity to participate here this evening.

HEARING OFFICER MYERS-WILKINS: Thank you.

Jennifer Sublett?

MS. SUBLETT: Hello. My name is Jennifer Sublett (S-u-b-l-e-t-t). I am a citizen of Springfield and also a CWLP customer.

I wanted to point out something about some of the previous comments by Mr. Burns and some others about how we have low utility rates, which is probably the case if you compare us statewide, but what no one has mentioned is that if this plant moves forward, our utility rates are expected to increase by 34 percent. For every $100, you spend on your utility bill now, add another 34 to that.

The City of Springfield recently passed an indoor smoking ban yet those same aldermen

59

have given the go ahead to this power plant without considering the effects of more air pollution and more emissions to our health including the risk of more frequent and more severe asthma attacks.

This proposed power plant does not include the use of any renewable sources of energy. Wind power for instance produces no harmful air emissions and is completely renewable unlike coal as a source of power.

Illinois also ranked sixth in the nation for emissions of mercury from coal-fired power plants. That's based on the USEPA's 2003 data.

As most people may know, every single lake, river and stream in Illinois currently has a fish consumption advisory due to mercury pollution which recommends limiting fish consumption from our local waters due to health concerns from the mercury.

I think that our community, CWLP, and our city council can do better using the cleanest available coal plant technology such as an IGCC or gasification plant.

I do see many union members here

60

tonight which is great, and I would like to remind the audience that construction of an IGCC plant or a wind farm plant or other sources would also create construction jobs here in Springfield.

In closing, I'd like to remind the audience members that this proposed plant will be owned by the City of Springfield and to speak to your aldermen about using a cleaner source of power and including clean renewable energy sources as well.

This permit should not move forward as currently requested.

Thank you.

HEARING OFFICER MYERS-WILKINS: Thank you.

Jim Kane?

MR. KANE: Hello. My name is Jim Kane, and I'm a ratepayer in Springfield. I don't represent anybody except fellow ratepayers.

I've lived in Springfield most of my life and enjoyed the low rates, and even with that increase that the young lady mentioned just a minute ago, we'll still have some of the lowest rates in the State of Illinois. Trust me, I live outside of

Springfield now, and I pay some of the higher rates in the State of Illinois.

I've worked on other projects where they bring in more efficient things, and I'm assuming that's what they're going to do with the newer plant. It will be the primary plant, and not only will you phase out the two older plants and get rid of those, but you'll also reduce the amount of emissions that you'll have in the existing plants, you know, because you'll be primarily using the more efficient one.

Now, as far as particulates that cause cancer, my in-laws, they lived in Mt. Pulaski which is nowhere near any power plant but both of them died of cancer but it was mostly because of cigarettes they smoked.

I can't say anything about power plants being your major cause of cancer but I think it's probably something else.

Thank you.

HEARING OFFICER MYERS-WILKINS: Thank you.

Bill Crook?

MR. CROOK: My name is Bill Crook.

62

Last name is spelled C-r-o-o-k. I've lived in Springfield all my life, and my concern is that when this plant was proposed, which was right after the year 2000, there was some awareness of global warming. It was a topic but I think our awareness has increased.

Tonight when I was listening to the car radio driving over here, a fellow who had written a book on global warming was talking about it. When we look ahead 50 years from now, it is going to be a serious problem to address.

As far as this power plant goes, sure it's going to be more efficient than the old plants. When I was growing up I remember smelling the sulfur dioxide all over Springfield, and it was horrible.

We've come a long way since then, but I want to look ahead 50 years in the future now and I want to see nonpolluting energy sources that we can see on the horizon, but we need a commitment to those.

I think we could ask 10 to 20 percent of our electric generation should come from renewable sources like wind, solar power, or geothermal hydroelectric. I know not everything is

63

practical in this geography we have here. Everything is flat here, but just the same, I'd like to see a vision for the future, and we don't need such a big plant if we can reduce our peak demand, and we need commitment to a green sustainable future, and I'd like to ask the EPA to look at reducing the size of this plant and considering generation from other renewable sources.

Thank you.

HEARING OFFICER MYERS-WILKINS: Tom Guthrie?

MR. GUTHRIE: I'm Tom Guthrie (G-u-t-h-r-i-e), and I don't have any statement. I just have a couple questions as clarification.

From what I understand, the proposed plant is going to be a larger generating facility than what we're closing down but at the same time, it's going to be newer technology, and with the dispatching, the older units now will not run as much as they are currently running.

In looking at this, does that not

mean that our overall emissions are going to decrease? That's my question. That's what I'm trying to figure out as I sat here.

MR. ROMAINE: Certain pollutants will certainly decrease. Given the difference in control technology between the units that are being shut down and the new unit, emissions will certainly decrease for sulfur dioxide emissions. Emissions of some pollutants will certainly decrease given the difference in control technology. For example, emissions of sulfur dioxide will decrease.

In terms of the change in particulate matter emissions, there will certainly be an immediate decrease in particulate matter emissions as you've described.

However, this plant is being built to address future demand, and at some point in the future, it would be reasonable to expect that with the growth of Springfield, there would be an increase in particulate matter emissions.

MR. GUTHRIE: Thank you.

HEARING OFFICER MYERS-WILKINS: Thank you.

Yatty Eli? Matty Eli?

Okay. That has concluded our registered commenters.

Becky Clayborn would like to speak

further, so at this point, we'll take a few comments if there are comments, and then we'll bring this hearing to a close.

Becky?

MR. ROMAINE: Well, is there anybody else? Before Becky speaks, is there anybody who hasn't signed up?

HEARING OFFICER MYERS-WILKINS: Is there anyone else interested in speaking or commenting?

MR. CREWS: Hi. Damon Crews (C-r-e-w-s), IBEW member.

I've also been an asthmatic for 25 years; went to two or three specialists, and it's kind of funny, they've never mentioned particulates from a power plant or anything like that, but it seems like seasonal changes it.

So my big point I guess is if this is such a big issue, why hasn't a doctor ever brought that up to me or anybody else that's been an asthmatic?

It seems like they're trying to better the pollution in the Springfield area, and, you know, I'd just like to make the point I'm an

66

asthmatic, and I'm all for this power plant.

Thanks.

HEARING OFFICER MYERS-WILKINS: Thank you.

Is there anyone else?

MS. KINSELLA: Hi. I'm Carrie

Kinsella (K-i-n-s-e-l-l-a). I'm a member of the local Sierra Club as well, and I just wanted to add my voice to some others here.

They mentioned earlier that as part of the process, an analysis of the alternatives including IGGC or gasification as well as wind power was conducted, yet coal-fired, the traditional method, the dirtier method was determined to be in Springfield's best interests.

I'd like to see a greater emphasis on exploration of cleaner renewable energy sources, ones that promote air quality in our community. This can be effectively combined with the focus on consumer conservation efforts. There are things that we can do as individuals to be more energy efficient and impact the community's needs.

We also need to consider the magnitude of this proposed power plant. This is an

increase from 75 megawatts to 250 megawatts. That's fairly significant, and again, this is a coal-fired power plant. It's not the cleanest energy source.

I've heard citizens talk tonight about financial concerns, and we can all appreciate that money is important. However, our rates are anticipated to go up 34 percent, and in addition to that, CWLP plans to sell off the additional power generator.

Thank you.

HEARING OFFICER MYERS-WILKINS: Thank

you.

MS. HAMMER: Hi everybody. My name is Ann Hammer. I am currently a graduate student at the University of Illinois-Springfield in the environmental studies program. We have a class here who's representing environmental issues.

Some of the things that I've heard tonight are specifically economic based, and I feel that building a power plant just in order to save jobs, and I don't want to offend anybody, but I think that's looking more at today, and power is something that we're going to have to deal with for the rest of our lives, for the rest of human

history, and we need to start thinking about ways that are going to be sustainable such as wind power.

Excuse me. I'm really nervous.

We have to start thinking about what the future is going to be. This plant is going to be around for 50 years. We have to start thinking about the price of coal and the availability of coal and what that's going to be doing to us.

Some of the health issues that we're starting to see now are going to be compounded as the future goes on. 50 years is a lot of time, and our population is going to be growing quite a bit over this time period, and by using so much more coal, we're going to be just expanding, and we're going to be making these problems worse it seems like, the particular problems, the sulfur dioxide and all that kind of stuff.

So I guess my point is that I think we should start looking into renewable energies, and I think we have this opportunity here today and in this permit process to really make a difference.

Some other people have said that this is the time to do it, and I think that's basically what I'm saying.

I'm sorry. I kind of lost my concentration.

HEARING OFFICER MYERS-WILKINS: Thank you.

MR. CORMIER: Hello. My name is Chip Cormier (C-o-r-m-i-e-r). I've been on both sides of this game. I dug the coal for 16 years out at Peabody 10, and now I'm a union electrician with Local 193.

Everybody keeps bringing up the fact that a 75-megawatt power plant is going to go down and a 200-megawatt is going in its place, but the one thing that nobody brought up here is, much like the Lake 2 project that keeps getting stalled and stalled and stalled, do you think they're going to quit building on the west side? Do you think they're going to quit building all the stores and the Wal-Marts and everything else that requires power? Do you think the grid of City, Water, Light & Power is not going to continue to get bigger and bigger and bigger?

There will be a need in the very near

future for a 200-megawatt station in this town, and you just want to look at that number, 75 watt, 200

watt. Oh, there will be a need because they're not going to stop building.

Are you going to stop building your homes? No.

There will be a continued increase in demand for City, Water, Light & Power generation capacity, and by burying your head in the sand and not realizing that you have to have that power, the ability to generate that power as the need arises, you will end up like California, and you will have rolling brownouts, and then you will have a little different perspective on whether this plant should have been built or not.

I urge you to pass this and go forward with the construction.

HEARING OFFICER MYERS-WILKINS: Thank you.

MR. BULLARD: My name is Clark Bullard (B-u-l-l-a-r-d).

My family has lived in Springfield for over a hundred years. I myself have been a homeowner for over 60 years, and I know how much we rely on power plants, electrical energy, energy to run everything we need.

I take my hat off to the electricians for the wonderful job they've done this last week in cleaning up after the tornado. All of the laborers in Springfield have contributed. I don't think you guys are going to be out of work if they built a different type of power plant. We're still going to use electricity, and the electricity use is going to expand.

We've used coal forever, since I can remember and before. There's been a lot of progress made, and coal has been supplemented, and oil and gasoline have come in to take its place.

We need energy, but why keep using our natural resources that are eventually going to run out. Coal has done a wonderful job, yes, but it's not going to last forever. Oil is running out now. We're having gasoline and oil problems. Why not look to energy production that is not going to run out.

The sun is going to keep on shining as long as people live. Wind is going to keep on blowing, and there's no pollution or health problems involved in such energy.

Why not make some progress and build

power plants that are going to be usable for another hundred years instead of having to run out of coal in another 50 years and have to figure on something else then. Why not look to the future and build something a bit more permanent.

Thank you.

HEARING OFFICER MYERS-WILKINS: Thank

you.

Other comments?

MR. TOMASKO: My name is Jim Tomasko (T-o-m-a-s-k-o). I'm a member of Local 193 also out of Springfield.

I have small children. I hear the Sierra Club talk about pollution coming up in the future.

I'd really like to know how many people around here drove in singly in a car tonight. That's a large pollutant.

You know, I'm all for renewable resources, but I don't hear a solution. I don't hear a plan on that side, and I think this project has been going forward since 2000. That's six years ago. There's been no solution put forward with that. We have a solution here with CWLP. They have

come up with a powerhouse. They have come up with a mean. They have come up with new engineering technology. They're probably going to use the best available, you know, and cut down on pollution and everything, that's great.

To look towards the future, that doesn't mean that we have to operate this thing at 100 percent. If there is another renewable energy resource to come up in the future ten, fifteen years from now that works at a higher efficiency rate, that's great. Then we could scale down the plant and come up with that, wind power or something I else like that.

There's not been a study. I haven't heard anybody say anything about a study they've done on wind power around here.

You know, we just need solutions. Everybody needs to work together, but I think this plant right here is the best solution we have for right now.

It might not agree with everybody and nobody get along with it but it's what we have right now, guys.

Unless somebody comes up with

something different and can come up right now with solutions for it, I don't know, I back this.

Thanks.

HEARING OFFICER MYERS-WILKINS: Thank you.

MS. EDWARDS: Hi. My name is Jeannie Edwards. I am a Springfield resident, a CWLP customer. I'm also a teacher at Springfield High School. I'm also a graduate student at the University of Illinois taking the environmental studies course.

As a group we are kind of sitting back there discussing, and we just had a few questions as far as the whole process.

I know that a lot of times it's been mentioned already that this has been in the works for a long time and now it's six years later and why all these questions, so we're kind of wondering from the application process to now, from November of '04 when the plant application was submitted to March of '06, why does it take so long to have a public hearing, and is there any solution to that as to getting that time period smaller so these concerns can be brought up before the plan is so close to

implementation?

MR. ROMAINE: We don't begin this stage of public involvement until we have completed our technical review of the application, prepared a draft permit, and are ready to accept public comments on our proposed action to issue a permit.

We would not be involving the public if we had decided that the application wasn't adequate yet, so this is really a public hearing to get comments on our proposed action on the application. It isn't a public hearing to really receive comments on the project as it's been developed over the years by Springfield CWLP.

MS. EDWARDS: Another question we had for you, are there conditions under which the IEPA would deny the permit other than if the permit did not meet current standards? What would it take for the permit to not be met?

MR. ROMAINE: This is a process that's governed by applicable law and regulations.

If the application demonstrates that the project will comply with applicable law and regulations, we are obligated to issue the permit for the project.

So to demonstrate that a permit shouldn't be issued, we need to have a showing that in some respect we have overlooked some applicable requirement and that this project will not be able to comply with that requirement.

MS. EDWARDS: Okay. And my third and final question for you is, as the agency of environmental protection, why does the IEPA not encourage power companies to look into alternative energy rather than dirty coal plants?

Is there some form they have to submit that they've looked into these alternative energy resources before they can submit their permit for this or is that not a portion of that?

MR. ROMAINE: That is not something that we undertake in the context of review of proposed sources of pollution.

We look at proposed sources of pollution to determine whether the project would comply with applicable regulations.

The efforts undertaken by the State of Illinois to support renewable energy, energy efficiency, are shared among a number of agencies. Much more critical for the role of state government

in those activities is the Department of Commerce and Economic Opportunity.

Even though we're called the

Environmental Protection Agency, a lot of what our programs deal with is addressing pollution.

MS. BURNS: Thank you.

HEARING OFFICER MYERS-WILKINS: Thank you.

Are there any more comments or questions?

MR. WELCH: James Welch, a member of IBEW 193 also.

There's a lot of wind around here. I froze my tail off yesterday on top of a roof changing out a service here in Springfield. It was a windy day. Some days there's no wind. I have a sale boat also. Some days we'll get out there and we'll sit.

I don't know what the Sierra Club's idea is for what you do on the days there's no wind. If that's the whole notion of what the plan is for the future, we don't want coal, let's use wind, that's fine. We need electricity every single day though. That's what a coal-fired power plant will

78

do, provide power every single day.

Others said we have 200 megawatts of power available. We aren't going to use 200 megawatts every single day. In the future if you want to use wind power, fine, bring it in when that technology is available. We'll use 10 megawatts if you can provide another 85 from wind. That's fine. Anything to reduce our rates, reduce the effects of our air that we breathe in day to day.

And the younger generation that's over there, I know that they're advocating for cleaner air for the future. I would be for my kids also, so that's something we have to look forward to.

But really, the benefits, as the young lady mentioned earlier, for right now we don't want to build a power plant, I'd be ashamed to, if we built it right now because we wanted to keep workers busy or keep electricity going. I'd be ashamed to do that.

But right now, as we mentioned, the effects are right now, and we have Lakeside, one of the dirtiest places possibly around. Right now we

79

have Dallman built in the late '70s they mentioned earlier. That's what we have right now, and the technology we have available that CWLP has brought forth is what we have right now available to us.

So in the right now, we already have plans to build this power plant approved by the EPA and by CWLP to be advantageous for us to build this plant. I think that's the move we ought to go forward with.

These are people who were trained and professionals in their fields, people who know what we should be doing with our environment.

And Sierra Club, I honor you. Really, you guys are wholeheartedly going after something you believe in. I was a paramedic for a number of years. I saw people who had asthmatic diseases and sicknesses. I worked on a number of those people who died suffocating. I can see that side of it also, but we really have to focus on the here and now, and the here and now is that we have a plan in action, and that should go wholeheartedly forward.

Thank you.

HEARING OFFICER MYERS-WILKINS: Is

there anyone else?

MS. HUGHES: I spoke before. I don't want to be the last person to speak. We all come from where we've been, what we believe, what we do for a living, what we've seen in our lives, and it's very hard to not have that be a part of what we feel about this issue.

I did want to say to the gentleman who has asthma whose doctor didn't associate it with particulate matter, there are ozone warnings, there are other warnings that people get in communities where there are problems with air quality. They advise that people with respiratory problems don't go out on those days or protect themselves. So he may not have said that, but that's a part of what that's all about.

And for anybody who has questions about studies that have been done, medical studies that have been done on the association of air quality with health problems, with respiratory illness and cardiac disease as well, I'd be happy to provide those. I will be providing them to the IEPA also.

Thank you.

HEARING OFFICER MYERS-WILKINS: Thank you.

MS. CLAYBORN: This is the point when everybody leaves, right?

My name is Becky Clayborn again, Sierra Club regional representative.

I'm so glad that somebody asked what the solution was because there are a lot of communities that have a solution to dirty new coal-fired power plants, and before I get to that though, I have to point out that, yes, this has been going on for six years. People have been planning this for six years, but how many of you knew that it was going on for six years and how many people -- oh, yeah, because you work for people that will get jobs for you for the power plants.

AUDIENCE COMMENT: We read the paper.

MS. CLAYBORN: It's been in the paper, and I can tell you that the people that I have talked to that have read about it in the paper said, oh, it's a done deal, isn't it? There was no discussion. If there was a discussion, it wasn't the entire community.

The community did not have a good

say, a good public participation. The first public meeting that CWLP gave to the public about the new power plant was at a Sierra Club meeting for Sierra Club members.

So I think that it really is important. I'm not joking when I say public participation is important. I like to hear everybody's side of the story, not just mine.

But the solution. Many communities are finding that energy efficiency practices such as better building codes, new lights for energy efficient light bulbs, for stop lights, for street lights, for lights inside, those types of practices and insulation of houses, those three things can get ten percent reduction in energy needs.

I'm not sure what the number is for how much CWLP needs right now, but isn't it like 500 megawatts that you guys provide? I think. Okay. So ten percent off of that, okay, that's 50 megawatts, okay, that you don't have to produce. That's free power.

As soon as you put in these newfangled technologies that they've got, you save power, and you don't have to build a plant to make

that 50 megawatts.

Renewable energy, Austin, Texas has put into place -- and many communities are doing this, I'm just picking one -- has put into place renewable energy requirements so that they have to have 20 percent of their energy come from renewable energy which is nonpolluting for the most part.

Obviously, every energy has something that you could find wrong with it, but 20 percent of the energy would come from a renewable source. That's a hundred megawatts, so that's 150 megawatts right there that we don't have to build in a coal-fired power plant.

I think that's a pretty good solution. I personally would never say don't build any coal ever but it's not the cleanest coal and it's a lot bigger than it needs to be. That's the solution.

And in terms of wind energy, I just wanted to point out as well that ELPC, Environmental Law and Policy Center, has done a study of wind potential in the upper Midwest. In the upper Midwest states, if all the wind was developed in the upper Midwest states, it could provide 25 percent of

84

the entire U.S. needs in energy, 25 percent of everybody's energy needs. It is feasible.

There's a 400-megawatt plant going in right up the street, Bloomington. It's not pie in the sky. It's happening now, and now I'm going to go on to the boring technical stuff that IEPA likes to hear about.

The netting exercise that we had talked about with the NOx, I looked it up, and the Illinois Administrative Code says that the two-year period which immediately precedes the particular date... Do you know what I'm talking about?

MR. ROMAINE: I do.

MS. CLAYBORN: It's 35 AIC 203.104.

MR. ROMAINE: That's certainly a set of the Illinois regulations. However, the particular regulation that's at issue here dealing with nitrogen oxide emissions is the federal prevention of significant deterioration regulations.

Certainly we can examine the netting analysis and make sure that it's been properly conducted. We certainly would not have any difficulty if as a result of that CWLP had to commit to slightly tighter numbers for NOx. That would be

great.

MS. CLAYBORN: Okay. Thank you.

Another question I had for EPA. In the application that CWLP gave to you, they had a list of hazardous air pollutants, emission levels that they expected. Oh, I'm sorry. They have a list of hazardous air pollution emissions that were in their application that had an emission limitation for those hazardous air pollutants, but it wasn't actually in the permit when the permit came out, so the permit application had more HAPs in it than the actual permit application did.

MR. ROMAINE: That's correct. When we issue permits, we focus in on key pollutants for dealing with this plant. Since most of the hazardous air pollutants of concern are particulate matter, we're addressing them through the limit on particulate matter emissions.

There aren't specific control technologies that are applied for emissions of air pollutants other than mercury. That is sort of the exception where it is desirable that a plant specifically include things such as activated carbon injection to minimize emissions of mercury.

MS. CLAYBORN: So if a power company in their permit says we can reach these limits on these hazardous pollutants, EPA, even if the company offers that information, it's still not put in the permit. Can we put it in the permit?

MR. ROMAINE: It could be in the permit. I would have to talk to CWLP whether it expected those representations of emissions to be converted into limits in its permit.

MS. CLAYBORN: Great.

Another issue that we had, a concern that we had is that the startups and shutdowns are excluded in the permit. It's not clear what the emission limits are during the startup/shutdown and during times of malfunction, and we're concerned that those periods of time are going to be overlooked and that there's going to be a significant amount of emissions that are coming out during the shutdown periods as they're shutting down and as they're starting up.

MR. ROMAINE: Those emissions are

addressed by the permit. However, given the variable conditions during those periods of time, we have an alternative approach to dealing with them.

We set limits on the total amount of emissions. We also have qualitative requirements, work practices that have to be followed to minimize the emissions that occur during those transient conditions.

MS. CLAYBORN: What part of the permit, do you know, that addresses that, or can you just put that in the responsiveness summary?

MR. ROMAINE: We can talk later this evening.

MS. CLAYBORN: Thank you.

Another concern is the particulate matter, filterable particulate matter limit that sets -- sorry. I'm reading my notes.

The draft permit has .015 pounds per million btu for filterable particulate matter, and there are examples of other permits with a lower number, and we're going to have these in our comments, our written comments to you, but I'd like to point out that Trimble Power Company in Kentucky and Y Gen 2 in Wyoming has .012. That's the lowest one that we've seen. And Inter-Mountain Power Generating Station has .013.

Like I said, we'll have that in the written comments for you, and we'd like you to

address that in the responsiveness summary and hopefully lower the number.

Similarly, H_2SO_4 limits, we've seen lower limits in other similar facilities. We'll put that in the written comments too.

The good combustion control that keeps being referred to in the permit as the BACT standard has never been defined anywhere in the permit, and so we'd like to see a definition of what good combustion control means and how it's measured I guess, and I think that's it.

I thank you so much for having this public hearing and letting us voice our concerns.

Thank you.

HEARING OFFICER MYERS-WILKINS: Thank you.

Now that everyone has had an opportunity to express their comments and questions, at least everyone who has desired to has had that opportunity, as we bring this meeting to a close, I just want to remind everyone that the comment period for this record or for information in this matter closes on April 21, 2006, so any written comments must be received by me before midnight on that date

89

or must be postmarked before midnight.

Copies of exhibits will be available upon request. The time is now 8:58 or so, and this meeting is adjourned. Thank you all for coming.

(Which were all of the proceedings held at this time.)

STATE OF ILLINOIS)
)SS.
COUNTY OF SANGAMON)

CERTIFICATE

Laurel A. Patkes, Certified Shorthand Reporter in and for said County and State, do hereby certify that I reported in shorthand the foregoing proceedings and that the foregoing is a true and correct transcript of my shorthand notes so taken as aforesaid.

I further certify that I am in no way associated with or related to any of the parties or attorneys involved herein, nor am I financially interested in this action.

Dated this 27th day of March 2006.

____
Certified Shorthand Reporter

Laure