IEPA Response to USEPA Permit Comments

The comments below were made by USEPA on the Winnetka Title V Permit during the public notice period. A response from IEPA regarding these USEPA comments is provided within this document to clarify, discuss, and resolve these comments.

USEPA Comment 1: It is not clear from either the draft permit or the statement of basis (SOB) what changes were addressed by Construction Permits 89080012 and 92090051, which were issued to the source for changes to boilers BLR #5 and BLR #7, and whether these changes resulted in modifications to boilers BLR #5 and BLR #7, as defined at 40 C.F.R. §60.14.

In discussions with IEPA, we understand that the above mentioned changes were related to conversion of the affected units from coal-fired units to gaseous and liquid-fueled units. However, such a discussion is not included in the SOB or draft permit. Additionally, neither the draft permit nor the SOB explains why the changes would not be classified as modifications to the affected units, as defined at 40 C.F.R. §§ 60.14, 60.40da, 60.40b, and/or 60.40c, as applicable. Please provide this explanation in either the draft permit or the SOB.

IEPA Response:

<u>BLR #5 and BLR #7</u>

Construction Permit 89080012 was a construction permit issued to the source to allow for the burning of natural gas or fuel oil in lieu of coal for Boiler #5. This change is not considered a modification to the unit for purpose of 40 CFR 60, Subpart Dc, because the change did not meet the definition of a modification provided by 40 CFR 60.2.

Construction Permit 92090051 was a construction permit issued to the source to allow for the burning of natural gas or fuel oil in lieu of coal for Boiler #7. This permit also limited the firing rate of this boiler to 102 mmBTU/hr or below. Also, Condition 6(b) of Construction Permit 92090051 states that, "Furthermore, as a result of the prior operation of Boiler #7, this permit is issued based on the proposed conversion of the boiler to natural gas and fuel oil firing not constituting a new source subject to the New Source Performance Standard (NSPS) for Steam Generators, 40 CFR 60, Subpart Db." 40 CFR Part 60, Subparts Db and Dc include standards for NOx, PM, and SO2.

After reviewing the associated construction permits, IEPA believes that it is unlikely that the conversion of Boilers #5 and #7 from these coal-fired units to natural gas-fired units (with fuel oil used for back-up only) in 1989 and 1992, respectively, triggered modifications to these units as addressed in 40 CFR 60.14. This is because, according to the information that was available to IEPA in the associated permit applications 89080012 and 92090051, it is unlikely that the heat input ratings of these units significantly increased after completion of the changes (i.e., conversion of coal to natural gas with fuel oil backup). Specifically, 40 CFR 60.14(h) states that "No physical change, or change in the method of operation, at an existing electric utility steam generating unit shall be treated as a modification for the purposes of this section provided that such change does not increase the maximum hourly emissions of any pollutant regulated under this section above the maximum hourly emissions achievable at that unit during the 5 years prior to the change." Provided the heat input ratings of Boilers #5 and #7 did not significantly increase after completion of the 1989 and 1992 changes, IEPA estimates that post-change maximum hourly emissions based on natural gas consumption would be lower than pre-change maximum hourly emissions. Boiler #5 NOx, SO2 and PM, respectively (pre/post, lb/mmBTU) are estimated at 1.1/0.1,3.9/0.0006 and 3.9/0.008. Boiler #7 NOx, SO2 and PM, respectively (pre/post) are estimated at 1.1/0.3,3.9/0.0006 and 3.9/0.008.

As shown, the maximum theoretical emissions of NO_x, PM and SO_2 in lb/mmBtu after the 1989 and 1992 changes to Boilers #5 and #7, respectively, are significantly lower than the maximum theoretical pre-change emissions in lb/mmBtu. Therefore, it appears evident that the 1989 and 1992 changes to these boilers did not result in an increase in maximum hourly emissions

---

USEPA Comment 2: The permit record does not demonstrate that the periodic monitoring provisions in the draft permit are adequate to assure continuous compliance with the numerical emissions limits for particulate matter (PM), nitrogen oxides (NO_x), sulfur dioxide (SO_2), and carbon monoxide (CO).

The draft permit includes hourly and annual numerical emissions limits for PM, NOx, SO_2 and CO in the units of pounds per hour (lb/hr), pounds per million British thermal units (lb/mmBtu), tons per year (tpy) and parts per million (ppm) in conditions 4.2.2(b)(i)(A) and 4.2.4(b)(iii)(A)(I) (PM limits), conditions 4.2.2(e)(i)(B) and 4.2.2(e)(i)(E) (NO_x limits), conditions 4.2.2(c)(i)(A) and 4.2.4(b)(iii)(C)(I) ($S0_2$ limits), and condition 4.2.2(d)(i)(A) (CO limits). These emissions limits originate from Construction Permits 89080012 and 92090051 and Illinois' State Implementation Plan. However, neither the draft permit nor the SOB explains how the source will quantify emissions to demonstrate compliance with these emissions limits. In addition, it is not clear from either the draft permit or the SOB how the permit's requirements to maintain records of emissions "with supporting calculations" and to conduct monthly inspections of the emissions units will assure compliance with the numerical emissions limits. Please either show, based on actual historical emissions data, that actual emissions from the affected units are expected to be significantly lower than the applicable emissions limits regardless of whether the affected units burn diesel fuel or natural gas, or add emissions testing requirements to the permit to ensure actual quantification of emissions. Note that verification of emissions from these units is especially critical because of the age of the units and the fact that neither of the affected units is subject to a national emissions standard.

IEPA Response:

Conditions 4.2.2(b)(i)(A) and 4.2.4(b)(iii)(A)(I) (PM limits):

In general, units firing natural gas have very low concentrations of PM. Natural gas is considered a “clean fuel”. Requiring a source to burn pipeline quality natural gas can be shown to demonstrate ongoing compliance with PM standards, and therefore, a record to verify that the source fired pipeline quality natural gas should be a sufficient compliance demonstration.

AP-42 was used to estimate PM emissions from the boilers. However, as a result of the age of the boilers, AP-42 emission factors may not be greatly reliable. Also, it was noted that there was only a 2%

margin of compliance for the PM limit using AP-42, which would suggest that PM testing is justifiable. Therefore, PM testing has been included, and is based on the same permitting techniques as the requirement to test for NOx (See NOx discussion below)

Conditions 4.2.2(c)(i)(A) and 4.2.4(b)(iii)(C)(I) ($S0_2$ limits):

Generally, natural gas fired units have a substantial margin of compliance with SO_2 standards. Natural gas is considered a "clean fuel" and contains very low concentrations of sulfur. Requiring a source to burn pipeline quality natural gas can be shown to demonstrate ongoing compliance with SO_2 standards, and therefore, a record to verify that the source fired pipeline quality natural gas should be a sufficient compliance demonstration. Using a simple mass balance approach it can be verified that no SO_2 standard or limitation will be exceeded.

Also an estimate of the emissions of SO_2 from each boiler was performed, which provided that a 99% or greater margin of compliance was demonstrated while firing natural gas and/or ultra low sulfur diesel fuel.

The results show de minimis levels of SO_2 emissions as directly related to the sulfur content of the fuel(s). Therefore, a record and requirement to fire only pipeline quality natural gas and ultra-low sulfur diesel fuel results is considered adequate monitoring for these units.

Condition 4.2.2(d)(i)(A) (CO limit):

CO emissions are a result of incomplete combustion. CO results when there is insufficient residence time at high temperature or incomplete mixing to complete the final step in fuel carbon oxidation.

The likelihood of natural gas combustion violating CO standards/limits is unlikely given that pipeline quality natural gas has a reliable carbon to hydrogen composition (> 75% methane) and since the standards/limits are typically based on worst-case operating conditions. The likelihood of distillate fuel oil violating the CO standards/limits is equally unlikely given that the standards/limits are typically based on worst-case operating conditions and the fact that ultra-low sulfur diesel fuel is a steady burning fuel. The proposed periodic monitoring is sufficient for these emission units because there is a small likelihood of an exceedance based on the inherent nature (discussed above) of natural gas and/or fuel oil and the margin of compliance routinely observed from emission tests on other similar units.

Conditions 4.2.2(e)(i)(B) and 4.2.2(e)(i)(E) (NO_x limits):

Based on estimates of NO_x emissions from the boilers, IEPA would agree that for $NO_{x,}$. given the age of the boilers and the former compliance demonstrations, the likelihood of an exceedance has a high enough probablility to warrant testing requirements in the permit. The compliance margins on average were 10% or less for natural gas and 15% or less for diesel fuel.

As a result, the Illinois EPA has added testing requirements for NO_x and PM when firing eith natural gas or diesel fuel. Given the infrequent operation of the boilers, the Illinois EPA has chosen to require a frequency that is dependent on the hours of operation, such that the boilers do not need to be started for the sole purpose of testing. The Illinois EPA prefers not to generate additional emissions for the sole purpose of performing compliance demonstrations. See Condition 4.2.2(e)(ii)(C) of the Permit.

<u>USEPA Comment 3(a):</u> Condition 4.2.2(a)(ii) requires the source to perform observations for opacity on the boilers in accordance with EPA Method 22 at least once every calendar year, followed by corrective action and follow-up Method 22 observations if visible emissions are observed, and subsequent EPA Method 9 observations if visible emissions continue. Because some of the boilers (i.e., Boilers BLR #4, BLR #5 and BLR #7) are permitted to fire both natural gas and fuel oil, EPA suggests that the visible emissions observations be conducted when the boilers fire fuel oil since, under normal operation, higher opacity emissions would be expected when the boilers fire fuel oil than when they fire natural gas.

IEPA Response:

"Normal Operation" for these boilers is operation while firing natural gas. The source has informed the IEPA that diesel fuel firing has not occurred in any boiler since January 1, 2000. The only time that fuel oil would be fired by the boilers at the source is during an unforeseeable event, such as a natural gas supply disruption or curtailment.

A permit requirement for the source to perform annual observations during the firing of fuel oil would not be an accurate representation of "normal operation" at the source. This type of requirement also has a high probability of causing an actual increase in overall source emissions by requiring the firing of fuel oil on an annual basis for the sole purpose of performing opacity observations; when in fact, the source has historically not fired fuel oil in the boilers in well over a decade.

Therefore, the IEPA believes that ongoing compliance with the opacity standard during "normal operation" is assured by the periodic monitoring provided by Condition 4.2.2(a)(ii). In the event that the source would fire fuel oil in a boiler for a period that extends beyond 24 hours, IEPA has added further monitoring/recordkeeping in Conditions 4.2.2(a)(ii)(A)(II) and 4.2.2(a)(ii)(D) to ensure that compliance may be demonstrated during fuel oil firing.

<u>USEPA Comment 3(b):</u> Condition 4.1.2(a)(ii)(A) requires the source to perform observations for opacity on each engine in accordance with EPA Method 9 at least once every calendar year. However, the SOB explains that EPA Method 22 observations must be performed annually for these units, and that EPA Method 9 observations are only performed if required by IEPA. *See* SOB at 13. We understand from discussions with the permit writer that the statement in the SOB is incorrect. Please clarify this discrepancy.

IEPA Response: Correct. The SOB contained an error and the Permit has the intended monitoring.

<u>USEPA Comment 3(c):</u> Please correct a numbering error in condition 4.2.2(e)(ii). The draft permit includes two conditions numbered 4.2.2(e)(ii)(A).

IEPA Response: Agreed. The error has been corrected.

USEPA Comment 3(d): Please correct a numbering error in condition 4.2.3(c). The draft permit includes two conditions numbered 4.2.3(c).

IEPA Response: Agreed. This error has been corrected.
