ILLINOIS ENVIRONMENTAL PROTECTION AGENCY
BUREAU OF AIR
PERMIT SECTION

DECEMBER 2013

RESPONSIVENESS SUMMARY FOR PUBLIC QUESTIONS AND COMMENTS ON THE APPLICATIONS FOR AIR POLLUTION CONTROL CONSTRUCTION PERMITS FOR THE FUTUREGEN 2.0 PROJECT

Source Identification No.: 137805AAA
Application Nos.: 12020013 and 12020051

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DECISION

On December 13, 2013, the Illinois Environmental Protection Agency (Illinois EPA) issued an air pollution control construction permit to Ameren Energy medina Valley Cogeneration, LLC (Ameren) and the FutureGen Industrial Alliance, Inc. (Alliance) for construction of an oxy-combustion power plant at the existing Meredosia Energy Center at 800 South Washington Street, in Meredosia, Illinois.

On December 13, 2013, the Illinois EPA also issued a second air pollution control construction permit to the Alliance for construction of a backup engine to be located at the site of the separate carbon dioxide sequestration facility in rural Morgan County.

Copies of the documents can be obtained from the contact listed at the end of this document. The permits and additional copies of this document can also be obtained from the Illinois EPA website www.epa.state.il.us/public-notices/.

BACKGROUND

On February 9, 2012, the Illinois EPA, Bureau of Air received an application from Ameren and the Alliance requesting a permit to construct a coal-fired oxy-combustion power plant at Ameren's existing power plant in Meredosia. The proposed project would be developed to enable the use of carbon capture and sequestration technology, with a portion of the carbon dioxide (CO_2) emissions from the plant being captured and sent by pipeline to a sequestration facility about 30 miles east of the plant.

The construction permit issued for the project identifies the applicable rules governing emissions from the plant, and establishes enforceable limits on its emissions. The permit also establishes appropriate compliance procedures, including requirements for emissions testing, continuous emission monitoring, recordkeeping, and reporting. The source will be required to carry out these procedures on an ongoing basis to demonstrate that the plant is operating within the limits established by the permit and that emissions are being properly controlled.

On February 9, 2012, the Illinois EPA, Bureau of Air also received an application from the Alliance for a construction permit for an oil-fired engine generator to provide electricity to buildings during power outages at the sequestration site. This construction permit, as well, identifies the applicable rules governing emissions from the plant, and establishes enforceable limitations on its emissions. The permit also establishes appropriate compliance procedures, including requirements for opacity observations, recordkeeping and reporting

COMMENT PERIOD AND PUBLIC HEARING

The Illinois EPA Bureau of Air evaluates applications and issues permits for sources of emissions. An air permit application must appropriately address compliance with applicable air pollution control laws and regulations before a permit can be issued. Following its initial review of the applications, the Illinois EPA Bureau of Air made a preliminary determination that the applications met the standards for issuance of a construction permit and prepared draft permits for public review and comment.

The public comment period began with the publication of a notice in the Jacksonville Journal-Courier on August 24, 2013. The notice was published again in the Jacksonville Journal-Courier on August 31 and September 7, 2013. A public hearing was held on October 9, 2013, at the Meredosia High School to receive oral comments and answer questions regarding the applications and the draft air permits. The comment period closed on November 8, 2013.

AVAILABILITY OF DOCUMENTS

The permit issued to Ameren/Alliance, the second permit issued to the Alliance and this responsiveness summary are available on the Illinois Permit Database at www.epa.gov/region5/air/permits/ilonline.htm (please look for the documents under All Permit Records (sorted by name), Construction Permit Records). Copies of these documents may also be obtained by contacting the Illinois EPA at the telephone numbers listed at the end of this document.

GENERAL COMMENTS

The proposal to issue a permit for the construction of an oxy-combustion power plant at the existing Meredosia Energy Center and a permit for a backup engine to be located at the site of the separate carbon dioxide (CO_2) sequestration facility in rural Morgan County has generated a variety of comments from the public and environmental organizations. The comments that were submitted were helpful to the Illinois EPA in the decision making process and these comments were fully considered by the Illinois EPA prior to issuance of these permits.

The Illinois EPA received numerous general comments and comments on the proposed FutureGen project. Representative examples of these general comments are listed below without response. Specific comments that address topics that are relevant to this permitting decision, with responses, follow in subsequent section.

Comments in Support of the Project

The project will mean more jobs, more business, increased tax revenue, and increased economic spending. As a member of the business community, I also understand the need for clean fuel and clean utilities that will replace those that are causing more pollution. This project has been well-considered and well-received in the area, and I firmly believe it will be one of the cleanest energy projects in the world.

The working men and women of central Illinois desperately need good-paying jobs that provide benefits for their families. FutureGen will provide these jobs. The world-leading clean-coal project will create an average of 620 well-paying jobs for the next 20 years. In addition, a brisk construction period will see this project generate as many as 1610 total jobs (direct and indirect) for the State of Illinois as work reaches its peak on the power plant retrofit, the CO_2 pipeline that will stretch from Meredosia to the northeast corner of Morgan County, the CO_2 injection well system and the construction of the new visitor research and training facility. Jacksonville, Morgan County and central Illinois need this boost of this project and the jobs it will bring.

This project means more than just some new jobs. It represents an economic development engine for Morgan County and the state. This will be a boon to the Illinois economy and will put Morgan County on the global stage of energy technology innovation.

Future Gen 2.0 is a $1.65 billion capital project jointly sponsored by the United States Department of Energy (USDOE) and a group of international energy-sector companies. It is the world's first large-scale, integrated demonstration project of oxy-combustion advanced clean coal technology with carbon capture and sequestration (CCS). Construction of a new visitor/research center and a training facility in the Jacksonville area is also part of the plan.

I support this project. The application itself, the Illinois EPA, and the monitoring that will go with it seem to protect the citizens in the area. I live very close to the plant. Also the economic development benefits of the program are needed here in the area.

FutureGen represents an excellent opportunity to give the community an economic shot in the arm during the construction phase as well as the ongoing operation. In the long term FutureGen will produce, in addition to jobs, increased tax revenues and more than replace the jobs that had been lost due to the closure of the Meredosia power plant in 2011.

Approximately 60 percent of power in rural America is based on coal-fired power plants. So coal is very important to rural America. However, with ever-tightening environmental regulations, new technology is needed to make coal cleaner. Even though this project may do very little as far as global warming, it is a start, a start in the right direction.

FutureGen has a great opportunity to demonstrate this clean-coal technology. So let's build this plant and protect the coal power of rural America. The Jacksonville Regional Development Corporation, including myself, fully supports issuing this permit.

<u>Comments in Opposition to the Project</u>

This project is designed to thwart climate change by reducing CO_2. However, this project will have no effect on the amount of CO_2 removed from or in the atmosphere. It is less than 1/10th of 1 percent. The net changes in CO_2 emissions from FutureGen 2.0 are so small, that my calculations show that it would take 2127.66 like-kind FutureGen 2.0 projects per year to reduce atmospheric CO_2 by just 1 ppm.

FutureGen does not consider who will be responsible for covering possible escalating costs of FutureGen 2.0. Carbon capture and sequestration have a history of exceeding costs. The first FutureGen project was abandoned in 2010 due to increased project costs. Mississippi Power Company's Kemper integrated gasification combined cycle power plant costs doubled throughout the course of the project. Most of Kemper's $4 billion price tag will be paid by ratepayers in economically depressed communities of color. The state of Illinois has bound its utilities to purchase electricity from FutureGen 2.0 for 20 years, without any commitment regarding the rates that will be charged to customers. This is a huge blunder or a huge sell-out.

FutureGen 2.0 includes the construction of a large "show place" facility featuring the FutureGen 2.0 project, including a visitor and research center, training facility and an arts center. The building is to be built on a 5 acre site in Jacksonville's Community Park. Mature trees will be cut down and space will be subtracted from various established activities held at the park. FutureGen 2.0 already has an office on Jacksonville's downtown square. This is a huge waste of money, money that would be better used for the actual project, particularly when projects like this go over budget. The visitor center at the Park smacks of ingratiation. It looks to me that the arts center is an add-on to appease the public for the unnecessary industrial move-in in our green Community Park.

I have long been disturbed by the FutureGen 2.0 project; hoping it would go away. To spend resources on a coal fired electric plant is poor judgment. Coal is an inefficient and outdated source of energy and coal-fired power plants are the dirtiest source of energy that is in use today.

The latest Cooperative Agreement between USDOE and FutureGen (Amendment 17) is on the website of the Illinois Commerce Commission. This amendment, filed on September 24, 2013 under ICC e-docket 13-0252, contains a risk assessment that indicates that FutureGen 2.0 is a high risk investment. I think it would be wise for all concerned to read the FutureGen Ex 13 Parts 1 and 2 prior to making a decision.

QUESTIONS AND COMMENTS WITH RESPONSES BY THE ILLINOIS EPA

(Each question or comment is followed by the response by the Illinois EPA in bold-face type.)

1. FutureGen 2.0 Alliance has publicly stated that this plant is supposed to be a near-zero emission coal-fired power plant because it is supposed to capture more than 90 percent of its climate-change-inducing CO_2 emissions and sequester it permanently. However, this draft permit falls far short of that goal. Rather than ensuring that FutureGen will actually capture 90 percent of its CO_2 emission, this draft permit would allow all of the CO_2 emissions it generates; none has to be captured, none has to be sequestered. This is not

FutureGen's intent. Therefore, I urge Illinois EPA to go back to the drawing board and come up with permit limits that match FutureGen's stated intent.

The FutureGen facility will be a demonstration project for use of carbon capture and sequestration (CCS) technology for control of emissions of CO_2. As such, it was not unreasonable for a permit application to have been submitted for this project that does not require this construction permit to set specific performance requirements for CCS. This avoids requirements related to the use of CCS by this facility that may not be able to be achieved, at least initially, as the facility would be a demonstration facility and would use technologies that have not been previously demonstrated at the scale of the proposed facility. At the same time, this facility will be subject to requirements related to control of CO_2 emissions and use of CCS that are imposed by the USDOE. The facility will likely be subject to requirements related to CCS that are established by USEPA in its new proposed New Source Performance Standards (NSPS) for Greenhouse Gas (GHG) Emissions of Electric Utility Generating Units (EGUs), 40 CFR 60 Subpart TTTT.

2. The facility would be able to emit excessive amounts of sulfur dioxide (SO_2), nitrogen oxides (NOx), fine particulate matter ($PM_{2.5}$), lead, and other pollutants. FutureGen may intend to do better, but this permit gives no assurance that it will.

As addressed by the construction permit that has been issued for the proposed facility, this facility is subject to various federal and state rules that limit its emissions of different pollutants. In particular, the emissions of the oxy-combustion boiler are limited by an existing NSPS, 40 CFR 60 Subpart Da, that addresses emissions of particulate matter, SO_2 and NOx, and by federal National Emission Standards for Hazardous Air Pollutants (NESHAP), 40 CFR 63 Subpart UUUUU, that address emissions of hazardous air pollutants (HAP).

3. USEPA recently prepared an NSPS for GHG Emissions from EGUs, 40 CFR 60 Subpart TTTT. The Illinois EPA should examine how FutureGen's plans to emit over one million tons of GHG annually would comply with these new standards. I disagree that these standards are not applicable because FutureGen proposes to offset the increase in GHG emissions from this facility with emissions decreases from the long-shuttered Meredosia Energy Center. This is legally problematic for two reasons. First, USEPA only allows a source to net out of Clean Air Act requirements if there are actual contemporaneous decreases in emissions, i.e., the emissions must fall within a period defined as five years before the proposed construction date of the new facility. That would mean that the emission reductions would have to have occurred between July of 2009 and July 2014. However, FutureGen Alliance is trying to use a contemporaneous period that goes back to February 2007, over seven years from when construction is expected to begin, which is two years beyond the allowable window for contemporaneous period.

As observed by this comment, the proposed facility will likely be subject to requirements under USEPA's proposed NSPS for GHG emissions from Electric

Utility Generating Units (EGUs). Once these rules are adopted by USEPA, these rules will address emissions of CO_2 from new EGUs. The proposed facility will likely be subject to these rules because construction on the facility will not commence prior to the publication of the rulemaking proposal in the Federal Register.[1] Based on the pre-publication version of this proposed rulemaking, these rules would set a standard for the CO_2 emissions of new coal-fired EGUs that would require the use of CO_2 sequestration. As the proposed facility would be developed to capture and sequester CO_2, it should meet the standard for CO_2 emissions that USEPA ultimately adopts, when these rules become applicable. With capture and sequestration of CO_2, the facility's actual emissions of CO_2 to the atmosphere would be much lower than its potential emissions of CO_2, as are addressed by the construction permit.

In this regard, nothing in this construction permit allows FutureGen to disregard this NSPS in the future when it becomes applicable. As discussed elsewhere in this document, NSPS are "self-executing." Based on the planned rulemaking proposal and Section 111(b) of the Clean Air Act, FutureGen will be subject to the requirements of the adopted NSPS for GHG emissions if construction on this facility commences after the proposed rule is published in the Federal Register, irrespective of this construction permit. The laws and rules that govern the applicability of NSPS, which are adopted by USEPA under Section 111 of the Clean Air Act, are different than the laws and rules that govern the PSD program, which is addressed by Sections 160 through 169 of the Clean Air Act. As explained elsewhere in this document, consistent with applicable law, rule and guidance, this project is not a major project for purposes of PSD due to decreases in emissions from the permanent shutdown of the existing boilers at the Meredosia Energy Center that are contemporaneous with this project. However, this does not shield the facility from other requirements that apply under the Clean Air Act, including NSPS rules.

4. USEPA has issued a series of guidance documents addressing whether a source that has been shut down is subject to PSD review upon reactivation. USEPA has evaluated such situations in terms of the permanence of the shutdowns based upon the intent of the owner or operator. The facts and circumstances of the particular case, including the duration of the shutdown and the handling of the shutdown by the State, are considered evidence of intent of the owner or operator. A shutdown lasting for two years or more or resulting in removal of the source from the emissions inventory of the state should be presumed permanent. Review of the record here shows that Ameren intended to shut down the Meredosia center permanently at the time of its closure.

[1] On September 20, 2013, USEPA Administrator Gina McCarthy signed the notice for this proposed rulemaking. As of December 12, 2013, based on the information on USEPA's website for this rulemaking (2013 Proposed Carbon Pollution Standard for New Power Plants), this notice had not yet been published in the Federal Register. Only a pre-publication version of this notice was available at this website. Refer to: http://www2.epa.gov/carbon-pollution-standards/2013-proposed-carbon-pollution-standard-new-power-plants.

The USEPA's reactivation policy is not applicable to this project. This policy addresses the proposed reactivation by a source of an emission unit that has not operated for an extended period of time following the permanent shutdown of the unit. As acknowledged in this comment, the policy provides for case-by-case consideration of specific facts including statements of intent by the owner and operator, the continued existence of the subject emission unit in a state's emission inventory and other factors.

In this case, none of the existing boilers at the Meredosia Energy Center will be reactivated or restarted. All the existing boilers will be permanently shutdown. This is a requirement in the construction permit that has been issued for the new oxy-combustion power facility. Since the existing boilers will not be reactivated, USEPA's reactivation policy is not relevant for these boilers.

The other existing emissions that will become part of the proposed facility are not affected by USEPA's reactivation policy. In this regard, Ameren and the Alliance submitted a permit application for this project, with the continued use of the Meredosia Energy Center, on February 9, 2012. This was only 40 days after the shutdown of Boilers 5 and 6, which occurred on January 1, 2012. Accordingly, the continued use of the Meredosia Energy Center was clearly planned separate from the shutdown of the existing boilers. In addition, Ameren currently maintains the buildings and equipment at the facility in light of their planned future use for this proposed project. The Illinois EPA's emission inventory continues to include emission units at the Meredosia Energy Center including the existing six boilers.[2] Ameren and the Alliance have continued to provide documentation to Illinois EPA showing their intent to continue operation of the Meredosia Energy Center consistent with this permitting action. Finally, Ameren has maintained all existing permits and has continued to pay all annual site fees.[3]

5. As noted in the draft Environmental Impact Statement for the proposed project prepared by the USDOE, the Meredosia Energy Center has not been operating for the last two years.[4] Ameren's 2011 annual report also refers to Meredosia's closure and its consequences for the company.[5] Ameren also disclosed to investors in its most recent annual report that the company has been required by the Illinois Pollution Control Board (IPCB) to refrain from operating the Meredosia Energy Center through December 31, 2020."[6] Nor does the facility have a valid operating permit, as the Title V permit for the

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[2] **As related to the federal Acid Rain Program, Ameren notified USEPA that the existing boilers were to be classified as long term cold storage units per 40 CFR 75.2 and 75.61. Ameren letter, March 7, 2012.**
[3] **Because Ameren appealed and received a stay of the Clean Air Act Permit program (CAAPP) permit for the Meredosia Energy Center issued in 2005, the state operating permits for the facility remain in effect.**
[4] *See* Draft Environmental Impact Statement for the FutureGen 2.0 Project (DOE/EIS-0460D), whose release was announced in the Federal Register (78 FR 26004, May 3, 2013).
[5] Ameren Annual Report and 10-K, 2011, at 8, 33, 47, 54, 68, 70, 77, 103, 104, 159, 167.
[6] Ameren Corporation, Form 10-K Annual Report for the Fiscal Year Ended December 31, 2012, available at http://www.sec.gov/Archives/edgar/data/18654/000144530513000414/aee-2012x1231x10k.html.

Meredosia Energy Center was stayed in 2005 and never took effect.[7] Data from USEPA databases confirms that this plant generated zero emissions in 2012.[8] Despite the clear indication that the Meredosia Energy Center was closed permanently in 2011, the draft permit would take its emissions from 2007 to 2009 into account in concluding that the FutureGen project will have lower emissions. This runs counter to USEPA guidelines and common sense.

Issues regarding shutdown and reactivation have already been addressed in the above discussion. While an IPCB order prohibits operation of the existing boilers at the Meredosia Energy Center, the FutureGen project is not subject to that prohibition. The statements in Ameren's 2011 annual report notwithstanding, Ameren's intention not to permanently cease operations at the Meredosia Energy Center is demonstrated by the various actions that have already been discussed, including the submittal of an application for this proposed project. The status of the Title V or CAAPP permit for the Meredosia Energy Center provides further evidence that continued operation is planned. This is because Ameren has not dropped its appeal of the issued CAAPP permit and this appeal is still pending before the IPCB.

In addition, as will be discussed in more detail in response to other comments, the shutdowns of the existing boilers at the Meredosia Energy Center are contemporaneous with the proposed FutureGen project. The amounts of those emission decreases were properly determined as the actual emissions of those boilers during a 24-month period preceding the shutdowns.

6. The residents surrounding the Meredosia Energy Center have breathed air free from its pollution for the last two years. The proposed project should be considered from this baseline of zero emissions. The same fuzzy math that the Applicant uses to avoid carbon regulations is also being used to avoid modern emission limits for all criteria pollutants, including SO_2, NOx, particulate matter and lead. The 7th Circuit has stated there is an expectation that as old plants wear out and are replaced by new ones, the new plants will be subject to "the more stringent pollution controls that the Clean Air Act imposes on the new plants." By allowing FutureGen to improperly credit Meredosia's old emissions to evade otherwise applicable standards, the draft permit contravenes the law.

As discussed, the proposed facility would be a new power plant and the oxy-combustion boiler would appropriately be subject to emissions standards that apply to new utility boilers. Only the applicability of the PSD rules is affected by the decreases in emissions due to the shutdown of existing boilers. The applicability of the PSD rules to a proposed project, that is, whether a proposed project is a major project, is governed by the net increases in emissions of different pollutants from a proposed project. These rules do not provide that only the emissions increases from

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[7] *See* DOE/EIS-0460D, p 3.1-8-9.
[8] Coal-fired Characteristics and Controls: 2012, USEPA. Clean Air Markets Program, *available at* http://www.epa.gov/airmarket/quarterlytracking.html.

a project must be considered. For this project, the PSD rules allow the decreases in emissions from the shutdown of the existing boilers to be considered in determining that that this project would not result in significant net increases in emissions and should not be considered a major project for purposes of the PSD rules.

In particular, as provided by 40 CFR 52.21(a)(2), the applicability of PSD requirements to proposed projects at an existing major source requires that the project results in both a significant increase in emissions, by itself, and a significant net emission increase as those terms are defined on a pollutant-by-pollutant basis. Therefore, to determine the applicability of PSD, first, the particular project's emissions are examined to determine whether the project, by itself, would result in a significant increase in emissions. In this case, the project, by itself, would be significant for a number of pollutants, including, NOx, SO_2, CO, PM, PM_{10}, $PM_{2.5}$, and GHG. For each pollutant for which there is a significant increase in emissions from the project, the second step is to determine whether there is a net emissions increase. This is the sum of the emissions increase from the project and the emissions increases and decreases from other projects in a contemporaneous 5-year time period preceding the date on which construction of the proposed project will commence (40 CFR 52.21(b)(3)(i)). If the sum of the project's emissions and the contemporaneous increases and decreases for other projects is not significant, the project is not a major project for that pollutant. In this case, the net emissions increases from the project will not be significant for any pollutants regulated by the PSD rules. Thus, the FutureGen project is not a major project for purposes of applicability of PSD review.

The comment argues that if emission units have recently ceased operations, the resulting emissions decreases should not be considered in determining the applicability of PSD to a future project at a source. However, the PSD rules (40 CFR 52.21(b)(3)(i)(b)) provide that a source may determine applicability of PSD for a future project considering emission decreases from past shutdowns at the source when those shutdowns are still contemporaneous. For the proposed FutureGen project, the shutdown of the existing boilers at the Meredosia Energy Center will be within the 5-year contemporaneous period specified by the PSD rules.

7. How will restarting the Meredosia Energy Center affect the multi-pollutant standard that Ameren agreed to in 2006?

The continuing operation of the Meredosia Energy Center as an oxy-combustion power plant will not affect the multi-pollutant standards under 35 IAC 225.233. These standards, which coordinate the timing of control requirements for emissions of mercury with certain requirements for control of NOx and SO_2 emissions, are applicable to Ameren's existing coal-fired electrical generating units. As a new generating unit, the new oxy-combustion facility will not be subject to the multi-pollutant standards but must directly comply with the standard for mercury emissions in 35 IAC 225.230(a)(1). ***See,*** **Condition 2.1.3-2(f).**

8. Concerning the multistep control train for removing pollutants from the flue gas, the first step is the circulating dry scrubber that uses hydrated lime to remove SO_2, other acid gases, and mercury. What are the waste streams generated from the circulating dry scrubber? Is the waste stream solid or wet?

The waste material from the Circulating Dry Scrubber (CDS), which will be composed of gypsum, ash and unreacted lime, will be removed from the flue gas as dry material by the downstream fabric filter. This waste stream will be analyzed to determine its regulatory classification and disposed of appropriately at an off-site commercial waste disposal facility.

9. The primary purpose of the polishing system for the oxy-combustion boiler, which includes a scrubber and baghouse, is to reduce the moisture content of the flue gas and adjust its temperature. Would this be direct contact, i.e., contact cooler polishing system? Are the waste streams generated from this dry, wet or both?

The waste generated by this polishing system (i.e., the Direct Contact Cooler - Polishing System or DCCPS) and its cooling tower, which involve direct contact with flue gas, is a wet stream. It will be addressed by the National Pollutant Discharge Elimination System (NPDES) permit for the Meredosia Energy Center. The waste from the baghouse that is downstream of the DCCPS is a dry stream.

10. Does Section 40 of Illinois Public Act 97-618 mean that the Illinois EPA, as a representative of the State of Illinois, must grant all necessary and appropriate permits no matter what? Is there an option for the Illinois EPA not to issue any permits? Section 40 of this Act reads

> Permitting. The State of Illinois shall issue to the Operator all necessary and appropriate permits consistent with State and federal law and corresponding regulations. The State of Illinois must allow the Operator to combine applications when appropriate, and the State of Illinois must otherwise streamline the application process for timely permit issuance.

The cited act, the Clean Coal Futuregen for Illinois Act of 2011, does not require that the Illinois EPA issue a construction permit "no matter what." The Illinois EPA has acted on the construction permit application for this project pursuant to Section 39(a) of Illinois' Environmental Protection Act. Section 39(a) of this Act generally addresses the circumstances under which the Illinois EPA shall or shall not issue a construction permit for a proposed facility. It provides, in relevant part, that when a permit is required for the construction of a facility "…the applicant shall apply to the Agency for such permit and it shall be the duty of the Agency to issue such a permit upon proof by the applicant that the facility …will not cause a violation of this Act or of regulations thereunder."

In fact, the scope of Section 40 of the Clean Coal Futuregen for Illinois Act of 2011, as addressed by this comment, is narrow. Section 40 of this act merely requires the State of Illinois to issue all necessary and appropriate permits for this project consistent with state law. As applied to the Illinois EPA, this means that the Illinois EPA must proceed in accordance with Illinois' Environmental Protection Act. Section 40 does not require the Illinois EPA to issue a construction permit in circumstances where the permit would be inconsistent with provisions of the Environmental Protection Act or associated regulations. Section 40 does little more than require the Illinois EPA to allow the operator to combine various permit applications, to the extent appropriate, and to streamline the application process.

11. I find it rather unsettling that under the wastewater permit all the cooling tower chemicals are listed. If you have ever been around a cooling tower, things can go wrong, and some of these chemicals can be discharged to the air. Some of these chemicals are very bad as an air pollutant. This was not addressed.

The emissions to the atmosphere of the chemicals that are used in cooling water are indirectly addressed by the wastewater permit under the NPDES program. As that permit sets requirement for the nature and/or amount of contaminants in the water that is circulated in the cooling towers, as related to discharges of wastewater to surface waters, it also serves to address other losses of these chemicals to the atmosphere, including emissions.

12. I raised some questions about the anti-fouling materials used in the cooling towers at a hearing on the FutureGen project held by USDOE. My husband, who is knowledgeable about cooling towers, says that the cooling towers are closed systems. That is, the water used in the boiler and the water in the cooling towers will be kept separate. Therefore, the chemicals in the boiler water are normally not emitted to the atmosphere. Given the nature of the chemicals used in the water used in the cooling towers, e.g., short lifespan of the chemicals, there should not be a problem from these chemicals.

The Illinois EPA agrees with the observations made in this comment.

13. What practices are going to be employed at the site to control fugitive dust and prevent fugitive dust from affecting area residents?

The haul roads at the site used by trucks carrying coal and other bulk materials must be paved. These roads must also be swept, flushed or vacuumed on a regular basis as needed to prevent the accumulation of excessive levels of dust (silt) on the roads, which would result in significant emissions of fugitive dust.

Emissions from coal handling operations must also be controlled to prevent nuisance emissions of fugitive dust. For the existing coal handling operations, which will not be modified, good housekeeping practices would be used consistent with the historic practices at the Meredosia Energy Center. The control practices for the two

new and modified operations must be sufficient to ensure ongoing compliance with the NSPS that addresses coal handling operations, 40 CFR 60 Subpart Y.

14. Given that there are multiple coal ash contamination sites throughout Illinois, I am glad water is not going to be used anymore to transport coal ash and to sort coal ash in wet impoundments. However, with dry ash handling comes fugitive dust.

The permit requires that emissions of particulate matter from handling of ash be effectively controlled using a combination of enclosure, filtration and work practices, i.e., mixing of water with the dry ash prior to loading out into trucks.

15. Other than CO_2, the increases in emissions with the proposed plant will <u>exceed</u> the significant emission thresholds for a major project under PSD rules. My local newspaper mentioned that coal to be used would be high sulfur. It seems all the emphasis is on capturing CO_2 which undoubtedly contributes to global warming and climate change but does not cause asthma, allergies, lung problems, acid rain and polluted water which other emissions cause and are present from every coal-fired power plant. CO_2 capture is the star of FutureGen 2.0, but pity the nearby inhabitants who have enjoyed a clear atmosphere during the facility shutdown, but who will now be affected by dirty air again.

As already discussed, emissions of pollutants besides CO_2 from the proposed facility must be appropriately controlled. There will not be either significant increases or significant net increases in emissions for each of the pollutants regulated under the PSD rules. This project will be accompanied by net decreases in emissions of most pollutants. In particular, the permitted emissions of SO_2 and NOx from the proposed facility, as allowed by the construction permit, are much less than the previous emissions of the Meredosia Energy Center. The permitted emissions of particulate matter are also less.

16. Using coal for energy has devastating environmental impacts during every point in its lifestyle. Mining coal from the ground damages lands, water and air. The transportation of coal by diesel trucks and trains adds emissions and dust to the atmosphere. The new oxy-combustion boiler will need 25 percent more coal than a traditional air boiler, thereby adding the increased emissions of pollutants other than CO_2.

Coal mines are subject to specific regulatory and permitting programs that have been developed to prevent and mitigate detrimental impacts from mining activity. This includes planning for ground subsidence, as is a particular concern for long wall mining, to prevent damage to structures, agricultural productivity and the natural environment, as well as provisions for land reclamation following completion of mining. As the coal mines that would supply the proposed facility would be separate sources from the Meredosia Energy Center, it is beyond the scope of this permit for the proposed facility to address the impacts of coal mining.

Similarly, regulatory programs have been developed and continue to evolve to address the emissions from the diesel engines in trucks and railroad locomotives. As trucks and locomotives are mobile sources, it is also beyond the scope of this permit for the proposed facility to address them.

It is certainly correct, as observed by this comment, that sequestration of CO_2 has costs. The proposed facility will use more coal for the electricity that it provides to the power grid than would be used by a comparable power plant without sequestration. However, pollution controls commonly have costs. These costs are justified by the adverse impacts to human health and welfare and to the environment that are avoided by the use of those controls. In this regard, the costs of CO_2 sequestration are not inconsequential but neither are the impacts of global warming and climate change. Moreover, CO_2 sequestration is only one step that will be needed if global emissions of CO_2 emissions are to be reduced. Improvements in energy efficiency and the generation of electricity with technologies that do not involve combustion of fuel, such as wind power, will also be important. These other approaches to avoiding CO_2 emissions also have the accompanying benefit of reducing emissions of other pollutants that accompany the generation of electricity.

17. I am concerned about the permanence of CO_2 storage schemes. The thrust of this demonstration project would be to reduce the amount of CO_2 to the atmosphere by putting over 350 million gallons of liquefied CO_2 per year under Illinois farm land to reduce the amount of CO_2 emissions to the atmosphere. Improper storage or lack of long term monitoring could lead to health risks to nearby populations, harm agriculture, create pressure changes causing ground heave, and even trigger seismic events. Safe and permanent storage cannot be guaranteed and even low leakage rates would undermine any climate mitigation effect. This is not a tried and tested process. In 1986, a large leakage of naturally sequestered CO_2 rose from Lake Nyos in Cameroon and asphyxiated 1,700 people. While the CO_2 had been sequestered naturally, the event could be evidence for the potentially catastrophic effects of sequestering carbon artificially. Local residents fear a potentially dangerous CO_2 leak and the lack of adequate evacuation procedures. Is future long term monitoring or a financial assurance plan to insure the long term stability of the CO_2 sequestration addressed?

Geological sequestration of CO_2 is subject to USEPA regulations that are designed to address the risks posed by sequestration and to prevent adverse impacts. In this regard, in December, 2010, USEPA adopted its "Class VI Rule" for underground injection of CO_2 for geologic sequestration, 40 CFR Part 146. This rule sets minimum technical criteria for permitting, geologic site characterization, area of review and corrective action, financial responsibility, well construction, operation, mechanical integrity testing, monitoring, sealing of wells, post-injection site care, and site closure of such wells. In Illinois, USEPA administers the permit program that implements this rule.

18. Adding a new coal-fired power plant in Illinois is extremely ill advised. The Applicant's own analysis shows that the area in which this new plant is proposed is already riddled with sulfur dioxide (SO_2) air quality levels that exceed the health-based National Ambient Air Quality Standard (NAAQS) by more than ten times. Permitting the addition of over 646,000 pounds (323 tons) per year of SO_2 to this area, which is already violating the NAAQS, is wrong.

The air quality in Illinois generally complies with the hourly NAAQS for SO_2. There are currently only two discrete areas in Illinois that are designated nonattainment areas for SO_2 in Illinois. One is the Pekin area, south of Peoria, and the other is the Lemont area, southwest of Chicago. In both areas the elevated levels of SO_2 are caused by the contribution of certain sources in those areas. Actions are underway to reduce SO_2 emissions in these areas to bring them into attainment.

This project will not add 323 tons of SO_2 emissions annually in Illinois. Rather, as will be discussed later in more detail, due to the contemporaneous decreases in emissions from the permanent shutdown of the six existing boilers at the Meredosia Energy Center, this project represents a net decrease in annual SO_2 emissions of over 9,000 tons.

Moreover, this comment grossly misrepresents the analysis of SO_2 air quality that the Applicant conducted for the proposed facility. In fact, this analysis was not prepared to address the current levels of air quality but the potential impacts of the proposed facility on air quality. The Applicant's analysis, which was independently reviewed by the Illinois EPA, shows that the impacts of the proposed project on any exceedances of the hourly SO_2 NAAQS would not be significant. The Applicant performed a cumulative assessment for the SO_2 considering both the SO_2 emissions of the facility and SO_2 emissions from existing sources in Central Illinois. For those receptors and times where the assessment showed a modeled exceedance of the SO_2 NAAQS, the modeled impacts of the proposed facility were not significant. The facility's greatest contribution at a particular receptor and time with a modeled exceedance was less than 15 percent of the applicable significant impact level (SIL). Accordingly, the SO_2 air quality assessment for the proposed project shows that it would not cause or contribute to SO_2 exceedances.

19. While there are no ozone monitors in Morgan County where the proposed project would be located, lack of air quality data does not make anyone safe. Ozone monitors are located in nearby Jersey and Sangamon Counties. Based on monitored ozone levels for 2010 through 2012, the ozone design value for Jersey County is 79 parts per billion (ppb), which exceeds the 2008, health-based ambient air quality standard for ozone, 75 ppb. The ozone monitor in Sangamon County was relocated in 2011, so there is not a design value for the period of 2010 through 2012. However, the 4th highest value recorded by the ozone monitor in Sangamon County in 2011 and 2012 were 79 ppb and 76 ppb, respectively. Thus, Sangamon County also appears to be headed for a nonattainment designation for ozone air quality. Permitting the addition of over

3,468,000 pounds per year of nitrogen dioxide (NOx), an ozone precursor, to this area that is already violating health based air quality standards is wrong.

Current levels of ozone in Central Illinois do not provide a basis to deny a permit for the proposed project. As a technical matter, this comment does not consider the nature of ozone air quality in Central Illinois or the role that individual sources have on ozone air quality. Elevated levels of ozone in Central Illinois are generally the result of transport of ozone and ozone precursors from sources located in the greater St. Louis Area (both Illinois and Missouri), including emissions from both stationary sources, like power plants, and cars, trucks and other mobile sources. Local emissions of ozone precursors in Central Illinois have little or no role in elevated levels of ozone that occur locally. Moreover, programs are underway to reduce the emissions of ozone precursors both in major urban areas and nationally to improve air quality. These are achieving gradual but steady improvements in air quality. This is shown by the design values for ozone for Jersey and Sangamon Counties for the period of 2011 through the end of the 2013 ozone season. Air quality in Jersey County, which is directly adjacent to the St. Louis area, has improved, with the design value for Jersey County now being 77 ppb. Continued attainment of the ozone air quality standard is shown in Sangamon County, which is significantly farther from the St. Louis Area, with an ozone design value of 72 ppb.

20. The Prevention of Significant Deterioration (PSD) program found in Part C of Title I of the federal Clean Air Act establishes the statutory framework for protecting public health and welfare from adverse effects of air pollution in areas designated attainment. Congress specified that the PSD program is intended to:

> insure that economic growth will occur in a manner consistent with the reservation of existing clean air resources"; and (2) "assure that any decision to permit increased air pollution . . . is made only after careful evaluation 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.

To accomplish these purposes, the Clean Air Act relies primarily on a preconstruction permitting program as the mechanism for reviewing proposals to increase air pollution in areas meeting the NAAQS. The Clean Air Act generally requires PSD permits prior to construction and/or operation of new major stationary sources and major modifications to stationary sources in areas designated attainment or unclassified for the pollutants to be emitted by the sources. See 42 U.S.C. §§ 7475 (a) and 7479(2)(C).[9]

[9] "Modification" is defined to include, "any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted." 42 U.S.C. § 7411(a)(4).

The Illinois EPA and the Applicant agree that the new oxy-combustion boiler and most of the other changes occurring because of the FutureGen 2.0 project are new construction and/or changes of operation. (For example, *See* the application, June 2013 submittal, p. 6, Table 3-1.) The Illinois EPA and the Applicant agree that these activities will create significant emission increases for certain regulated NSR pollutants.[10] The Applicant also claims that the increases in emissions of lead and fluorides from this project are not significant. (See application, June 2013 submittal, p. 21.) However, as explained in later comments, the increase in emissions of fluorides is significant.

Therefore, except for fluorides, the only issue with regard to PSD applicability is whether the changes cause significant net emission increases. The Applicant and the Illinois EPA claim that they do not. See, e.g. Draft Permit at Finding 3 ("this project will not be accompanied by significant net increases in emissions of PSD pollutants"). However, as detailed below, the changes do cause significant net emission increases for particulate matter (PM), particulate $matter_{10}$ (PM_{10}), particulate $matter_{2.5}$ ($PM_{2.5}$), sulfur dioxide (SO_2), nitrogen oxides (NOx), sulfuric acid mist, fluorides, and greenhouse gases. Thus, PSD is an applicable requirement for these pollutants, which requires the Applicant to obtain a PSD permit.

As will be discussed in response to specific comments, the proposed facility is not a major project under the federal PSD rules. There are contemporaneous decreases in emissions from the permanent shutdown of the existing boilers at the Meredosia Energy Center such that the net increases in emissions of regulated NSR pollutants from this project will not be significant.

21. In the application (June 2013 submittal, p. 16), the Applicant admits that for an emission decrease to be creditable under the PSD program, the following must be true. "All increases and decreases have occurred after the applicable minor source baseline date." See also 40 CFR 52.21(b)(3)(iv). While the Applicant clearly acknowledges that a decrease must occur after the minor source baseline date, the Applicant and the Illinois EPA completely fail to discuss this requirement, much less demonstrate that it is met.

As is necessary for <u>certain</u> pollutants, the requirement of 40 CFR 52.21(b)(3)(iv) is met by the emissions decreases from the shutdown of the existing boilers at the Meredosia Energy Center so these emissions decreases are creditable and may be considered in the netting analysis for the proposed project.

[10] For example, in the application (June 2013 Submittal, page 14), the Applicant states "FutureGen 2.0 emissions increases are greater than the significant emissions rates so the Project will result in a significant emissions increase as that term is defined in the US EPA regulations."

As related to emissions of SO_2, this requirement is met as the shutdown of the existing boilers at the Meredosia Energy Center, in fact, occurred after the minor source baseline date for SO_2, which is in 1985.[11]

As a more general matter, this comment misrepresents 40 CFR 52.21(b)(3)(iv), relying on an incomplete statement in the application that broadly suggests that decreases in emissions are not creditable for purposes of netting if they occur before the minor source baseline. In fact, this provision only addresses emissions of three pollutants, i.e., SO_2, particulate matter and nitrogen oxides (NOx). For decreases in emissions of these pollutants that occur before the minor source baseline date, this provision merely addresses an additional requirement on such decreases for them to be creditable for netting. These decreases must be considered in determining the "maximum allowable increases remaining available," more commonly referred to as the available PSD increment. As is necessary for certain pollutants, the decreases in emissions in the netting analysis for the proposed project meet this requirement and are creditable. In this regard, 40 CFR 52.21(b)(3)(iv), in its entirety, provides:

> **An increase or decrease in actual emissions of sulfur dioxide, particulate matter, or nitrogen oxides that occurs before the applicable minor source baseline date is creditable only if it is required to be considered in calculating the amount of maximum allowable increases remaining available.**

This requirement is satisfied for the decreases in emissions of particulate matter and NOx in the netting analysis for the proposed project.[12] This is because these decreases involve changes in actual emissions of particulate matter and NOx at a major stationary source (i.e., the Meredosia Energy Center) that occurred after the major source baseline date for these pollutants, i.e., January 6, 1975[13] and February 8, 1988, respectively. Thus, these decreases must be considered when determining the available PSD increments for particulate matter and NOx. In this regard, after the major source baseline date for a pollutant, the baseline concentration, which is the starting point for consumption or expansion of PSD increment, is not affected by changes in emissions at major sources, which changes in emissions accordingly affect the amount of increment that is available. Decreases in emissions at major sources act to expand the amount of increment that is available. (Increase in emissions at major sources act to consume available increment.) In this regard, in

[11] For SO_2, the minor source baseline date was set in Morgan County in 1985 when a source, Anderson Clayton, submitted an application for a PSD permit for the conversion of an existing boiler to coal (Construction Permit No. 84030035).

[12] As already discussed, this requirement is met for the decreases in SO_2 from the shutdowns of the existing boilers at the Meredosia Energy Center because they occurred after the minor source baseline date.

[13] The PSD rules no longer contain a major source baseline date specifically for particulate matter. As addressed by Section 166(f) of the Clean Air Act, USEPA has converted the major source baseline date originally established for particulate matter, January 6, 1975, into the major source baseline date for PM_{10}. In this regard, Section 166(f) of the Clean Air Act authorized the USEPA to substitute provisions for PSD increment in terms of PM_{10} for earlier provisions in terms of particulate matter.

the provisions of the PSD rules dealing with PSD increments, the definition of baseline concentration, 40 CFR 52.21(b)(13)(ii), provides:

> **The following will not be included in the baseline concentration and will affect the applicable maximum allowable increase(s):**
> ***(a)*****Actual emissions from any major stationary source on which construction commenced after January 6, 1975; …**

This subject was specifically addressed by USEPA in 1980 when it adopted the provisions of the PSD rules that provide for netting, including 40 CFR 52.21(b)(3)(iv). In the preamble to the adoption of these provisions, USEPA explains that emission decreases at major stationary sources that occur before the minor source baseline date are considered in determining the available increment. This action was taken to address the circumstances of projects, like the proposed project, that will occur at a major stationary source.[14]

> **EPA's policy under the June 1978 regulations is unclear as to whether emissions reductions prior to the baseline date increase the amount of available increments. The policy allows decreases after January 6, 1975, and prior to the baseline date, to be used by sources to offset subsequent increases from the requirement for an ambient air quality assessment, since the decreases permit later emissions increase at the same source to avoid the otherwise required air quality assessment. The policy did not state whether**

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[14] This approach to the available increment was subsequently confirmed in 2010 in the preamble to the adoption of the PSD increments for $PM_{2.5}$ and other revisions to the PSD rules to address $PM_{2.5}$.

> **To make this distinction between the date when emissions resulting from the construction at a major stationary source consume the increment and the date when emissions changes in general (*i.e.*, from both major and minor sources) begin to consume the increment, we established the terms "major source baseline date" and "minor source baseline date," respectively. *See* 40 CFR 51.166(b)(14) and 52.21(b)(14). Accordingly, the "major source baseline date," which precedes the trigger date, is the date after which actual emissions increases associated with construction at any major stationary source consume the PSD increment. In accordance with the statutory definition of "baseline concentration," the PSD regulations define a fixed date to represent the major source baseline date for each pollutant for which an increment exists. … In this final rule, as described later, we are establishing a separate major source baseline date for implementing the $PM_{2.5}$ increments. *See* section V.F of this preamble for further discussion of the major source baseline date for $PM_{2.5}$.**
>
> **The "minor source baseline date" is the earliest date after the trigger date on which a source or modification submits the first complete application for a PSD permit in a particular area. After the minor source baseline date, any increase in actual emissions (from both major and minor sources) consumes the PSD increment for that area.**
>
> **Once the minor source baseline date is established, the new emissions increase from that major source consumes a portion of the increment in that area, as do any subsequent actual emissions increases that occur from any new or existing source in the area.**
>
> **75 FR 64868 (Oct. 10, 2010).**

> **isolated decreases not made in conjunction with intrasource increase were considered to expand available increment. In contrast the policy is clear that emission reductions after the baseline date increase available increments.**
>
> **As a result of the revised definition of modification which permits offset credit for emission reductions occurring within a moving five-year period, EPA has decided to clarify its existing policy. All emission reductions prior to the baseline date at major stationary source will now be considered to expand available increment. Since contemporaneous emission reductions accomplished before the baseline date can be used by a source to offset a contemporaneous post-baseline emissions increase, and thereby avoid PSD review, it is also reasonable to allow these contemporaneous pre-baseline date reductions to expand the increment. Without this change, source owners that reduce emissions by retiring or controlling old equipment before the baseline date will be penalized by having increase after the baseline data count against increments even though the pre-baseline decrease might offset the later increase and eliminate the need for PSD review.**
>
> **45 FR 52720 (Aug. 7, 1980).**

It should be noted that this approach to increment consumption is facilitated by the definition of "construction" in the PSD rules. As construction is defined by 40 CFR 52.21(b)(8), it encompasses not only activities that increase emissions, such as modifications, but also activities that may increase or decrease emissions, e.g., changes in the method of operation of emission units, and activities that act to reduce emissions, i.e., the demolition of emission units. The definition of construction was intentionally developed in this way by USEPA to facilitate implementation of its approach to increment consumption and expansion. [15]

> **Construction means any physical change or change in the method of operation (including fabrication, erection, installation, demolition, or modification of an emissions unit) that would result in a change in emissions.**

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[15] **The definition of "construction" was specifically addressed by USEPA in 1980 when it adopted the provisions of the PSD rules that provide for netting. As explained in the preamble to this rulemaking,**

> **The changed policy [for increments] is reflected in a new definition of "construction" which is any physical change or change in the method of operation of a stationary source resulting in a change in the actual emissions of the source (including fabrication, erection, installation, demolition, or modification). Any construction commencing at a major source since January 6, 1975, may result in an increase or decrease in actual source emissions. If an actual decrease involving construction at a major stationary source occurs before the baseline date, the reduction will expand the available increment if it is included in a federally enforceable permit or SIP provision. An actual increase associated with construction activities at a major stationary source will consume increment.**
>
> **75 FR 52720 (Aug. 7, 1980).**

40 CFR 52.21(b)(8).

22. As already noted, in the application, the Applicant admits that for an emission decrease to be creditable under the PSD program, the following must be true. “All increases and decreases have occurred after the applicable minor source baseline date.” See also 40 CFR 52.21(b)(3)(iv). The decreases in $PM_{2.5}$ emissions from the shutdown of the existing boilers at the Meredosia Energy Center did not occur after the minor source baseline date for $PM_{2.5}$. The trigger date must occur before the minor source baseline date. After the trigger date, the minor source baseline date is established when the first complete PSD permit application covering the pollutant in question is filed for the area at issue. *See,* e.g. 75 FR 64,864, 64,868 (Oct. 20, 2010).

The trigger date for $PM_{2.5}$ is October 20, 2011, per 75 FR 64,887. Therefore, by definition, the minor source baseline date for $PM_{2.5}$ must be after October 20, 2011. According to the application (June 2013 submittal, p. 17), the decrease at Boilers 1 through 4 happened on November 9, 2009 when the boilers were removed from service. Thus, this decrease from Boilers 1 through 4 is not creditable because it happened before the $PM_{2.5}$ minor source baseline date.

According to the application (June 2013 submittal, p. 17), Boilers 5 and 6 were removed from service and created emission decreases, according to the Applicant, on January 1, 2012. However, the Applicant and the Illinois EPA did not claim (nor do I think they could) that a complete PSD application for a project in Morgan County subject to PSD for $PM_{2.5}$ was filed between October 21, 2011 and December 31, 2011. Thus, the decreases in $PM_{2.5}$ emissions from Boilers 5 and 6 are also not creditable. The fact that increase from the 2008 emergency engine generator is not creditable does not change the conclusion. The new equipment for FutureGen 2.0 will create an increase of 97 tpy of $PM_{2.5}$. There are no creditable decreases so the net increase is also 97 tpy of $PM_{2.5}$. This is above the significant emission rate of 10 tpy so FutureGen 2.0 triggers PSD for $PM_{2.5}$.

This comment also misrepresents 40 CFR 52.21(b)(3)(iv) by relying on an incomplete statement in the application to suggest that it applies to emissions of $PM_{2.5}$. This provision only addresses three pollutants, i.e. SO_2, particulate matter and NOx. It does not apply for emissions of $PM_{2.5}$. USEPA has addressed $PM_{2.5}$ as a new pollutant, distinct from emissions of particulate matter and PM_{10}. As discussed in the preamble to the adoption of the PSD increments for $PM_{2.5}$, the USEPA acted under the authority of Section 166(a) of the Clean Air Act and not under Section 166(f) of the Clean Air Act.[16] Accordingly, this comment does not

[16] Among other matters, Section 166(a) of the Clean Air Act addresses the establishment by USEPA of PSD increments for new pollutants for which NAAQS are adopted. Section 166(f) provides that increments for PM_{10} may be substituted for the increments for particulate matter that are specified by Sections 163(b) and 165(d)(2)(C)(iv) of the Clean Air Act.

In the preamble to the adoption of the PSD increments for $PM_{2.5}$ and other revisions to the PSD rules to address $PM_{2.5}$, USEPA explains that the increments for $PM_{2.5}$ are being adopted under Section 166(a) of the Clean Air Act.

show that decrease in emissions of $PM_{2.5}$ from the shutdown of the existing boilers at the Meredosia Energy Center is not creditable for purposes of netting.

At most, this comment observes that, as related to $PM_{2.5}$, the decreases in emissions from the shutdown of Boilers 1 through 4 occurred prior to the major source baseline date set by USEPA for $PM_{2.5}$, October 20, 2010. With respect to the decreases in emissions from the shutdown of Boilers 5 and 6, the comment acknowledges they that occurred after the major source baseline date for $PM_{2.5}$. It is undisputed that the decreases in emissions from the shutdown of the existing boilers occurred prior to the minor source baseline date for $PM_{2.5.}$ As theorized by this commenter, a PSD application has not been received for a project in Morgan County that is subject to PSD for $PM_{2.5}$.[17] However, as already discussed, emission decreases that occur at a major stationary source do not have to occur after the minor source baseline date to be creditable for purposes of netting.

In response to this comment, the Illinois EPA has further considered whether a revised netting analysis could be prepared for the proposed project for $PM_{2.5}$ that shows that the net increase in emissions of $PM_{2.5}$ is not significant only relying on the decreases in emissions from Boilers 5 and 6. That is, whether a netting analysis for the proposed project could show a less than significant net increase in emissions without relying on decreases from the shutdown of Boilers 1 through 4, which occurred before the major source baseline date for $PM_{2.5}$.

In fact, such a netting analysis could be prepared. The decrease in $PM_{2.5}$ emissions from just the shutdown of Boilers 5 and 6 is 103.8 tons/year.[18] Accordingly, the net

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> **For the reasons discussed previously in this preamble, EPA has decided to finalize the $PM_{2.5}$ increments under the authority of section 166(a) of the Act. With respect to the potential creation of $PM_{2.5}$ increments under section 166(f) (as discussed in the 2007 NPRM at 72 FR 54120-54121), we have not reached any final conclusion whether that approach is authorized by statute, but believe that such an approach raises significant legal issues. Because the Agency is not relying on section 166(f) in this rulemaking, we do not address these issues in this preamble, although some additional discussion is included in the response to Comments document for this rule.**
>
> **75 FR 64890 (Oct. 20, 2010).**

[17] The "trigger date" for $PM_{2.5}$, October 20, 2011, does not have any effect on this conclusion. The trigger date merely governs the earliest that the minor source baseline date may be set for a pollutant for which PSD increments have been established. The term is used in the definition of minor source baseline date, 40 CFR 52.21(b)(14)(i), which includes the trigger date for $PM_{2.5}$, October 20, 2011, as well the trigger dates for PM_{10} and SO_2, August 7, 1977 and the trigger date for NOx, February 8, 1988.

> **"Minor source baseline date" means the earliest date after the trigger date on which a major stationary source or major modification subject to 40 CFR 52.21 or to regulations approved pursuant to 40 CFR 51.166 submits a complete application under the relevant regulations. …**
>
> **40 CFR 52.21(b)(14)(ii).**

[18] The emissions of $PM_{2.5}$ during the baseline period selected by the Applicant, March 2007 through February 2009, were determined using data for heat input to these boilers that is available from USEPA on its Clean

increase in emissions of $PM_{2.5}$ from the proposed project is still not significant even if one does not consider the decreases in emissions from Boilers 1 through 4. Based on the $PM_{2.5}$ emissions that would have been allowed for this proposed project by the draft permit, 97.0 tpy, a revised netting analysis for $PM_{2.5}$ that only relies on the decrease in emissions from Boilers 5 and 6 would still show a net decrease in emissions of 9.0 tpy.[19] After considering the effect of the limit in the issued permit on the operation of the oxy-combustion boiler in air firing mode, the net decrease would become 28.8 tpy.[20]

To provide further assurance that the proposed project would not be significant for $PM_{2.5}$ even if Boilers 1 through 4 were not considered, the permitted $PM_{2.5}$ emissions of the auxiliary boiler have been lowered in the issued permit to reduce the $PM_{2.5}$ emissions of the proposed project.[21] For the auxiliary boiler, the application indicated PM_{10} and $PM_{2.5}$ emissions of 16.6 and 4.9 tpy, respectively. However, the draft permit would have limited both PM_{10} and $PM_{2.5}$ emissions to 16.6 tpy. In the issued permit, the $PM_{2.5}$ emissions of the auxiliary boiler are limited to 4.9 tpy, as reflected in the application, which lowers the permitted $PM_{2.5}$ emissions of the auxiliary boiler by 11.7 tpy. See Condition 2.2.6. With this change, the net decrease in $PM_{2.5}$ emissions of this project only considering the decrease in emissions from Boilers 5 and 6 would be 40.5 tpy.

23. An analysis similar to my analysis concerning creditability of decreases in emissions of $PM_{2.5}$ should also apply for decreases in emissions of PM, PM_{10}, SO_2 and NOx. Neither the Applicant nor Illinois EPA claims that the minor source baseline date was established

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Air Markets internet site. (This information was also provided by the Applicant in Attachment No. 9 in its February 2012 application submittal.)

Based on this data, the $PM_{2.5}$ emissions of Boiler 5 during this two-year period were 205.72 tons, for an annual emission decrease of 102.86 tpy.

(25,715,444 mmBtu x 0.016 lb/mmBtu ÷ 2000 lbs/ton = 205.72 tpy, 205.72 tpy ÷ 2 = 102.86 tpy)

The $PM_{2.5}$ emission of Boiler 6, which operated as a peaking unit, during these two years were only 1.99 tons. (99,654 mmBtu x 0.040 lb/mmBtu ÷ 2000 lbs/ton = 1.99 tpy, 1.99 tpy ÷ 2 = 0.99 tpy)

Combined, the overall decrease in $PM_{2.5}$ emissions from the shutdown of Boilers 5 and 6 is 103.85 tpy.

[19] The draft permit would have allowed $PM_{2.5}$ emissions of 97.0 tpy from the project. The baseline emissions of the main cooling tower (- 3.0 tpy) and a contemporaneous increase from the existing emergency engine generator at the Meredosia Energy Center (+ 0.8 tpy), produce a combined net change of -2.2 tpy. Accordingly, absent consideration of the emissions decreases from the existing boilers, the project would result in a net emission increase for $PM_{2.5}$ of 94.8 tpy (97.0 tpy – 2.2 tpy = 94.8 tpy). With the decrease in $PM_{2.5}$ emissions from Boilers 5 and 6, the net decrease in $PM_{2.5}$ emissions from this project would become -9.0 tpy. (94.8 tpy – 103.8 tpy = -9.0 tpy).

[20] Limiting operation of the oxy-combustion boiler to at most 4,800 years in air-firing mode reduces its permitted $PM_{2.5}$ emissions by 19.8 tpy, from 64.5 tpy to 45.3 tpy. With the decrease in $PM_{2.5}$ emissions from Boilers 5 and 6, the net decrease in $PM_{2.5}$ emissions from this project would become -9.0 tpy. ((94.8 tpy – 19.8 tpy) - 103.8 tpy = - 28.8 tpy)

[21] For purposes of consumption of PSD increment for $PM_{2.5}$ in Morgan County, it is desirable that the decreases in $PM_{2.5}$ be significantly greater than the permitted increases in emissions from this proposed project at the Meredosia Energy Center after the baseline date for $PM_{2.5}$. This will act to ensure that the overall effect of this project is to expand the available increments for $PM_{2.5}$.

for PM, PM_{10}, SO_2 or NOx in Morgan County before November 9, 2009 or January 1, 2012. I have no reason to believe that minor source baseline dates have ever been established for these pollutants in Morgan County. Thus, the decreases from the shutdown of Boilers 1 through 6 are not creditable for PM, PM_{10}, SO_2 or NOx. Therefore, FutureGen 2.0 causes a significant net emission increase for these pollutants, as well as a significant emission increase, triggering PSD.

As already discussed, decreases in emissions of particulate matter, SO_2 and NOx that occur at a major stationary source do not have to occur after the applicable minor source baseline date to be creditable for netting. This is because 40 CFR 52.21(b)(13)(ii) requires that such decreases be considered when determining the amounts of available increment. In addition, for PM_{10} and NOx, the emissions decreases occurred after the applicable major source baseline dates. For SO_2, the decreases in emissions occurred after both the applicable major source baseline date and the minor source baseline date, since the minor source baseline date for SO_2 was set for Morgan County in 1985.

24. In calculating the net emissions, the Applicant and the Illinois EPA under-calculated the emission increases from new equipment. They did not consider CO_2 from the scrubbers, that is, the hydrated lime used in the circulating dry scrubber and the trona used in the direct contact cooling/polishing system (DCCPS). Both of these systems produce CO_2 as a byproduct of the reaction with SO_2. However, this CO_2 was not considered.

The limits for emissions of greenhouse gases (GHG) in the permit, which address emissions of CO_2, reflect information in the application and are appropriate for assessing the increase and net increase in GHG emissions from this project for purposes of applicability of PSD. The permit includes appropriate monitoring requirements to verify compliance with the limits for the GHG emissions of this new facility. Most significantly, Condition 2.1.9-6 of the permit requires continuous emissions monitoring for the CO_2 emissions of the oxy-combustion boiler, which are projected to comprise over 99 percent of the GHG generated by this boiler.

This comment does not identify additional emissions of CO_2 from this new facility that would result in the net increase in the GHG emissions of the project being significant. For the oxy-combustion boiler, the circulating dry scrubber system, which is the primary control device for SO_2, will not generate CO_2. This is because the scrubbing agent is hydrated lime, not limestone. Only small amounts of CO_2 will be generated as a result of the control of SO_2 with trona in the DCCPS, which is the secondary control system for SO_2 emissions.[22] These emissions will not change the conclusion of the netting analysis for GHG emissions.

[22] **A conservative evaluation of the amount of CO_2 generated by the trona used in the DCCPS, disregarding any sequestration of this CO_2, can be made using the emission data in the application. As described in Table 3-2 of the application (June 2013 submittal, p.8), the amount of SO_2 controlled by the DCCPS is only about 155 pounds/hr. The amount of CO_2 from controlling this SO_2 would be about 112 pounds/hr or 500 tons/yr.**
Amount of SO_2 entering DCCPS = 163.6 pounds/hr

25. The Applicant and the Illinois EPA did not consider fugitive emissions from the coal in the coal trucks. I do not mean the emissions that the coal trucks generate off the road but rather coal that is blown out of the back of the coal truck while the coal trucks are on-site.

To the extent that any coal is lost from the coal trucks, it is appropriate to assume that it is deposited on the surface of roadways and contributes to the silt loading on the roadways. As such, "fugitive coal" is reasonably accounted for in both the application and in the permit. This comment does not provide a means by which the contribution of fugitive coal to emissions, if any, could be determined. In this regard, USEPA's methodology for determination of the emissions from roadways does not address direct emissions from the loss of trucks as they travel on roadways.[23]

26. The Applicant and the Illinois EPA underestimated fugitive emissions from the haul roads, as explained in the detailed evaluation of these emissions accompanying my comments. See Victoria R. Stamper, Evaluation of Particulate Matter Emissions from Haul Roads at the Proposed FutureGen 2.0 Project at the Meredosia Energy Center, Nov. 7, 2013 (Stamper Evaluation).

The fugitive emissions from roadways have not been underestimated, as explained in the following five responses to each of the specific points made in the summary section of the evaluation of emissions accompanying these comments. Indeed, the Applicant revised its initial data for emissions from roadways, increasing emissions, to ensure that the data did not underestimate emissions. *See,* August 21, 2013, email from Gregg Hagerty, URS Corporation, to Robert Smet, Illinois EPA.[24]

27. Fugitive emissions from the haul roads were underestimated because the permit does not identify which roads must be paved. The permit must clearly state which haul roads are to be paved and it must require the roads to be paved by the time the FutureGen project commences operation.

(SO_2 rate for air-firing rate mode adjusted for the load for oxy-combustion, 73.6 x 100/45 = 163.6 lbs/hr)
Amount of SO_2 leaving DCCPS = 9.99 pounds/hr
(SO_2 rate for oxy-combustion mode with bypass of CO_2 pipeline)
Amount of SO_2 controlled by the DCCPS = 154.6 pounds/hr
(difference between SO_2 entering and leaving the DCCPS, 163.6 – 9.9 = 154.6 lbs/hr)
Amount of CO_2 generated = 112 pounds/hr
(stoichiometry of the reaction, with one-to-one exchange of SO_2 and CO_2 and the respective molecular weights of SO_2 and CO_2, 154 x 46/64 = 112 lbs/hr)

[23] In its *Compilation of Air Pollutant Emission Factors,* AP-42, USEPA observes that "At industrial sites, surface loading is replenished by spillage of material and trackout from unpaved roads and staging areas." AP-42, 1/11, p 13.2.1-.1.

[24] In its original application submittal in February, 2012, the Applicant used a value for silt loading of 0.6 g/m^2 in its projections for roadway emissions. It subsequently submitted revised emission projections based on a value for silt loading of 2.0 g/m^2.

In response to this comment, an additional condition has been included in the issued permit, Condition 2.6.3(a). This condition specifies the principal roadways at the facility that must be paved, i.e., the haul roads for coal, lime, trona and ash and the roads that serve the parking lots for employees and visitors. This condition generally requires that paving must be completed no later than the date that the oxy-combustion boiler begins operation. However, the portions of roads in specific areas where they might be damaged by the continuing presence of construction equipment, such as cranes and tracked vehicles, must promptly be paved after that equipment is removed and paving would no longer be at risk of being damaged. This addresses the likelihood that heavy construction equipment will still be in place when the oxy-combustion boiler initially begins operation so that paving in certain areas would be damaged by that equipment.

28. Fugitive emissions from the haul roads were underestimated because of the approach to gravel roads. The particulate matter emissions for the portions of the haul roads that will be gravel must be properly accounted for in the projection of potential particulate matter increases from the haul roads.

As already discussed, the principal haul roads must be paved when the project begin operation. Regular deliveries and material removal will be conducted on these principal roadways. These principal roadways will also serve as the main traffic routes to employee and visitor parking areas.

29. Fugitive emissions from the haul roads were underestimated because the permit does not use an appropriate silt loading. The silt loading assumed in the projection of particulate matter emissions from haul roads must be reflective of the silt loadings expected from an industrial facility, not a public road.

In response to this comment, a condition has been included in the issued permit, requiring the source to measure silt loading on roadways at the facility (Condition 2.6.5-2).   This will ensure that compliance with the emission limits is accurately determined.

The comment does not show that a different value for silt loading should be used to determine emissions from roadways. The silt loading used by the Applicant for its revised emission data, 2 grams per square meter, reflects the Applicant's judgment for the future silt loading on haul roads at this facility. The information provided with this comment does not justify the use of a higher value for the silt loading, 8.2 g/m^2, and increasing the permitted particulate matter emissions from haul roads fourfold. The fact that higher values for silt loadings have been used for projects in other states does not justify use of a value for the proposed facility that is higher than the one that the Applicant has used. As acknowledged in the evaluation

submitted with this comment, historically, a wide range of silt loadings has been measured on roadways at different industrial facilities.[25]

30. Fugitive emissions from the haul roads have been underestimated because the permit does not limit the maximum amount of coal that may be handled. In projecting potential particulate matter emissions, the maximum annual amount of coal and all other materials hauled must be projected. My calculations of roadway emissions show that, when the paved road emissions are corrected to more properly account for silt loading and the maximum amount of coal that could be transported on the paved haul roads, emissions are significantly higher than projected by Ameren.

In response to this comment, the issued permit includes an additional condition limiting the amount of coal that is received by the facility by truck (Condition 2.6.3(d)). This makes this element in the application in the emissions calculations for roadways enforceable as both a legal and practical matter.[26] **As already discussed, it is not appropriate to use a higher value for silt loading in these calculations.**

31. When emissions from gravel roads are taken into account, particulate matter emissions from roadways at the facility will be even higher than the projections of emissions in the Stamper Evaluation ($PM_{2.5}$ at 1.709 tpy, PM_{10} at 6.961 tpy and PM at 34.804 tpy, as summarized in Table 3 of the Stamper Evaluation).

As previously discussed, in response to another comment, an additional condition has been included in the issued permit, Condition 2.6.3(a), that requires the principal roadways at the facility to be paved, with such paving to generally be completed by the time that the oxy-combustion boiler initially begins operation. The principal roadways at the facility are the haul roads for coal, lime, trona and ash and the roads that serve the parking lots for employees and visitors.

32. The application (June 2013 submittal, Executive Summary, p. 1, Figure ES-1) indicates that nitrogen is the only output from the air separation unit (ASU). The draft permit does not require any testing or monitoring to see if any NOx, ozone, CO_2, N_2O or methane is emitted from the ASU. All of these pollutants could be formed and emitted in the ASU because they are constituents of ambient air.

Testing or monitoring of the ASU, as requested by this comment, is not warranted. The ASU extracts or separates oxygen from air for utilization in the oxy-combustion boiler. The air, less extracted oxygen, is then returned to the atmosphere. The ASU does not convert constituents of the incoming air into pollutants or add pollutants into the incoming air and therefore is not an emission unit.

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[25] **In its *Compilation of Air Pollutant Emission Factors*, AP-42, USEPA reports mean values for silt loading on paved road roads at different types of industrial facilities. The lowest value of silt loading is for corn wet mills, 1.1 g/m^2. The highest value is for copper smelting facilities, 292 g/m^2. See AP-42, Table 13.2.1-3.**
[26] **Incidentally, as the calculations in the Stamper Evaluation were based on all coal being received at the facility by truck, rather than by a combination of truck and barge, those calculations overestimate emissions.**

33. The draft permit, Table 1B, indicates that the net emission increase for sulfuric acid mist is 6.92 tons per year (tpy), which is just 0.08 tpy below the significant emission rate for sulfuric acid mist, 7.0 tpy. However, the Applicant left out emissions of sulfuric acid mist from the emergency diesel engine generator permitted on November 21, 2008, Construction Permit No. 08100029, in its calculations. (See Project Summary, p. 5.) The diesel fuel burned in this engine contains sulfur. Therefore, the Applicant must quantify the potential emissions of sulfuric acid mist from this engine, as permitted in 2008, to see if, accepting all other premises, which I don't, these emissions would make the facility a major project for emissions of sulfuric acid mist.

Emissions of sulfuric acid mist from the existing emergency diesel generator would not make the facility a major project subject to PSD for emissions of sulfuric acid mist. The permitted SO_2 emissions of this generator are only 0.4 tons per year.[27] It is reasonable to assume that less than 2.0 percent of this SO_2 would be converted to SO_3 and actually emitted as sulfuric acid mist, for potential emissions of sulfuric acid mist of only 0.008 tpy.[28] Using this conservative assumption and also applying it auxiliary boiler and the new emergency engine at the sequestration facility, the net increase in the emissions of sulfuric acid mist from this project is still only 6.949 tpy, which is still less than 7.0 tpy and is not significant.[29]

While the permitted net increase in emissions of sulfuric acid mist for the proposed project is only slightly less than the significant emission rate for sulfuric acid mist, the netting analysis is very conservative. It assumes that the new facility will operate continuously without any outages for routine maintenance. This is not the case for any power plant and will certainly not be the case for this demonstration

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[27] Condition 5(a) of Construction Permit No. 08100029 limits the SO_2 emissions from this emergency engine to 0.4 lbs/hour and 0.4 tpy, which accommodates operation for 2,000 hours per year. As an engine that is regulated as an emergency engine under the National Emission Standards for Hazardous Air Pollutants (NESHAP) for Reciprocating Internal Combustion Engines, 40 CFR 63 Subpart ZZZZ, actual operation will be far less. The routine operation of this engine for purposes other than actual emergencies, e.g., readiness testing is limited to 100 hours per year by the NESHAP.

[28] According to USEPA's *Compilation of Air Pollutant Emission Factors*, AP-42, Section 3.3.3.5, "during the combustion process, essentially all the sulfur in the fuel is oxidized to SO_2." Given essentially all the sulfur is oxidized to SO_2, this leaves very little sulfur for conversion to sulfuric acid mist.

Consistent with USEPA's conclusion, a paper on the subject of emissions of sulfuric acid mist from the sulfur contained in fuel, emissions of sulfuric acid mist from firing of oil could be as much as 1.5 percent of the theoretical emissions of SO_2. See Larry S. Monroe, Southern Company Generation and Energy Marketing, *An Updated Method for Estimating Total Sulfuric Acid Mist Emissions from Stationary Power Plants*, Revised March 2003.

[29] Given the passage of time, it is also likely that a reevaluation of the net change in emissions for the proposed facility would now show that the increases in emissions from the construction of the emergency diesel engine are no longer contemporaneous with the proposed project. It is now over five years since the permit for this engine was issued. For the increases from this engine to still be contemporaneous, the installation and initial startup of this engine will have to have occurred within five years of commencement of construction of the oxy-combustion facility.

facility. The netting analysis is also based on a maximum value for the amount of time that this facility will operate in air-firing mode (i.e., is not operated in oxy-combustion mode). However, the purpose of this facility is to demonstrate both oxy-combustion technology and CO_2 sequestration technology. This inherently necessitates routine operation of the boiler in oxy-combustion mode.

34. I do not accept all the Applicant's other premises in calculating the net emission increases. In the application (June 2013 submittal, p. 8, Table 3-2), for air-firing, the Applicant assumed for the oxy-combustion boiler that the emission rate for sulfuric acid mist is 2.97 lb/hr. However, the Applicant also assumed that this boiler would only operate in air-firing for 4800 hours per year. (Application, June 2013 submittal, p. 7) This assumption would not be enforceable as a practical matter. The draft permit would not limit air firing of the oxy-combustion boiler to 4800 hours per year.

Indeed, Condition 2.1.1 of the draft permit explains that "In the event of an upset in the operation of the boiler or an outage or upset in the CO_2 pipeline or the sequestration facility, the boiler can transition back into air firing mode." While this is true, the draft permit, as written, would also allow operation of the oxy-combustion boiler in air-firing mode all the time. Air-firing mode is much more economical and efficient. The source could choose to operate in air firing mode for a variety of reasons such as outage or upset in the boiler, including the air separation unit, the CO_2 pipeline or the sequestration site. See Project Summary, p. 2. In addition, because the permit would not require carbon capture, it could be simply that the source chooses to operate the plant as a "traditional" pulverized coal plant. The ASU is very expensive to operate so the source will have a tremendous financial incentive to operate the boiler in air firing as much as possible. It is also critical to keep in mind that the conditions in this permit are permanent. The source's current intent can certainly change in the decades to come. Operating at full load air firing, this would be the only pulverized coal unit permitted in the last decade or longer without selective catalytic reduction.

In response to this comment, the issued permit explicitly limits the operation of the oxy-combustion boiler in air-firing mode to no more than 4,800 hours/year. In addition, the issued permit requires recordkeeping to verify compliance with this limit. (Conditions 2.1.6(a)(ii) and 2.1.10(b)(i).) This makes this element in the determination of the potential emissions of sulfuric acid mist from the facility enforceable as both a legal and practical matter. It should be recognized that this operational limit merely memorializes the intended operation of the boiler. As already discussed, this limit is conservative, i.e., being much greater than it is expected that this facility would ever actually operate in air-firing mode. This is because the initial purpose of this project is to evaluate and demonstrate oxy-combustion, which inherently necessitates operation of the boiler in oxy-combustion mode rather than air-firing mode.

The possible incentives to increase operation of the oxy-combustion boiler in air-firing mode in the future, as speculated upon by this comment, are not relevant

since operation in this mode is explicitly limited in the issued permit. Moreover, as discussed elsewhere, it is expected that the GHG emissions of the proposed facility will be subject to a New Source Performance Standards (NSPS) that will eventually be adopted by USEPA that will require that the bulk of the CO_2 generated by this facility be sequestered.[30] This will preclude routine operation of the facility in air-firing mode since the oxy-combustion boiler must be in oxy-combustion mode, not air-firing mode, to sequester CO_2 emissions.

The inclusion of a limit in the issued permit on the operation of the oxy-combustion boiler in air-firing mode (i.e., other than in oxy-combustion mode) also acts to reduce the increases and net increases in emissions for the proposed facility for pollutants other than sulfuric acid mist, including NOx, SO_2, PM and GHG. This is because the limits in the draft permit for these other pollutants reflected continuous operation in the mode of operation with highest emissions of each pollutant, most commonly air-firing.

35. As already mentioned, in the application (June 2013 submittal, p. 8, Table 3-2), for air-firing, the Applicant assumed that the sulfuric acid mist emission rate of the oxy-combustion boiler is 2.97 lb/hr. However, the Applicant also assumed that this boiler would only operate in air-firing at up to 45 percent load. (Application, June 2013 submittal, p. 7) This assumption would not be enforceable as a practical matter. The draft permit would not limit the load of the oxy-combustion boiler when air firing to 45 percent load.

This comment does not identify a flaw in the data for emissions of sulfuric mist from the oxy-combustion boiler for "air firing." This comment incorrectly assumes that the capacity of the oxy-combustion boiler in "air-firing mode" and "oxy-combustion mode" are identical and that the Applicant is relying on an "assumption" about the maximum level of operation during air firing. This is understandable given various statements made in the application that suggest that the emission data provided for this boiler in air-firing mode is based on operation of this boiler at 45 percent of its capacity. In fact, the output capacity of this boiler in air-firing mode will be significantly less than its capacity in oxy-combustion.[31] Above all else, the representations in the application about load during air-firing served to communicate this difference in the capacity of this boiler in air-firing and oxy-combustion modes. These statements do not show that the emission data for this

[30] Pre-publication notice of proposed rulemaking, Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units, signed by USEPA Administrator Gina McCarthy on September 20, 2013 [EPA-HQ-OAR-2013-0495; FRL-9839-4]. (As of December 12, 2013, USEPA's website for this rulemaking (2013 Proposed Carbon Pollution Standard for New Power Plants) indicated that this notice had not yet been published in the Federal Register.)

[31] As a technical matter, this is because the oxy-combustion boiler will be designed for oxy-combustion. The boiler will physically be smaller than a comparable boiler designed for air firing. Accordingly, various systems in the boiler that affect its capacity in air-firing mode, e.g., the combustion air system and the exhaust gas handling system, will be designed as if for a smaller boiler with less capacity since larger systems could not be productively utilized.

boiler submitted by the Applicant for emissions of sulfuric acid mist, or other pollutants, during air-firing was based simply on an assumption about the level of operation of this boiler during air-firing. The data in the application for the emissions of the oxy-combustion boiler during air-firing is appropriately used as the basis for the emission limits set by the permit.

To address the concern of this comment, a condition has been added in the issued permit, Condition 2.1.5(c), that limits the operation of the boiler to the load at which emission testing shows compliance with emissions limits for sulfuric acid mist, as well as fluorides. (For sulfuric acid mist, continuous emission monitoring is neither feasible nor warranted.[32]) This requires that this boiler be appropriately operated, on an ongoing basis, in a manner that is consistent with the manner in which this boiler was operated during emission testing in which compliance with the relevant limit was demonstrated. This approach ensures the practical enforceability of the emission limits for sulfuric acid mist. In addition to its use in permitting, this type of approach is used in a variety of air pollution control regulations, including: NSPS 40 CFR Part 60; National Emission Standards for Hazardous Air Pollutants ((NESHAP) 40 CFR Part 61 and 63; and Compliance Assurance Monitoring (CAM) 40 CFR Part 64. This approach is particularly apt in the circumstances of the proposed boiler. As a demonstration unit, notwithstanding its design and expected capacity in air-firing, there is a degree of uncertainty about the actual capacity of this boiler in air-firing. Air-firing is a secondary mode of operation of this boiler. The actual capacity of this boiler in air-firing, will only be able to be authoritatively and conclusively determined from the actual operation and performance of this boiler after it is constructed.

36. Minor status to avoid PSD must be calculated based on the potential to emit of emission units, that is, on maximum output, 100 percent load, and continuous operation, 8,760 hours per year, unless there is a physical or legal restriction. See 40 CFR 52.21(b)(4). Thus, the sulfuric acid mist emission factor for air-firing should be 6.6 lbs/hr (2.97 x 1.0/.45 = 6.6) as there is no physical or legal restriction on operating the oxy-combustion boiler in air-firing mode above 45 percent load. There is also no enforceable limit on hours of operation firing air. Therefore, the potential to emit must be based on continuous air-firing which results in potential emissions of 28.9 tpy (6.6 lbs/hr x 8,760 hrs /yr = 28.9 tpy). In the application (June 2013 submittal, p. 21, Table 3-9), the Applicant claims a contemporaneous emission decrease of 3.58 tpy of sulfuric acid mist. As explained in other comments, I dispute this claim. However, even if this decrease is accepted, the net increase in emissions of sulfuric acid mist is 25.3 tpy based on the increase from the oxy-combustion boiler alone. This is above the significant emission rate for sulfuric acid mist, 7.0 tpy, so FutureGen 2.0 is a major project subject to PSD for sulfuric acid mist.

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[32] Techniques to continuously monitor emissions of sulfuric acid mist from coal fired boilers have not been developed. As a general matter, the magnitude of the expected emissions also does not warrant continuous monitoring, certainly not until the actual levels of emissions are determined by testing.

As already discussed, the operation of the oxy-combustion boiler in air-firing mode will be physically and legally restricted. The load at which this boiler will be capable of operating in air-firing mode will be less than its maximum load in oxy-combustion mode. For both air-firing and oxy-combustion, the issued permit now limits the load at which the oxy-combustion boiler is operated to the load at which the relevant emission testing has shown compliance with the emission limits for sulfuric acid mist, as well as fluorides. The operation of the oxy-combustion boiler in air-firing mode is also limited to no more than 4,800 hours per year. Recordkeeping is required to verify compliance with these limits.

37. The limits on emissions of sulfuric acid mist in Draft Permit Condition 2.1.6(b) would not change my comments. The Draft Permit lacks testing, monitoring and reporting for sulfuric acid mist emissions. It does not even have a one-time stack test, much less continuous monitoring that applies at all times including startup, shutdown or malfunction. Thus, those limits do not change the potential to emit sulfuric acid mist, that I calculated, 28.9 tpy. (See 40 CFR 52.21(b)(4).) These limits also do not change the significant net increase that I calculated, 25.3 tpy.

The limits in the permit for sulfuric acid mist are enforceable as a practical matter. As mentioned in response to earlier comments, the issued permit requires that the emission testing required for the oxy-combustion boiler include measurements for emissions of sulfuric acid mist in both air-firing and oxy-combustion modes. (See Conditions 2.1.7(c)(i), (ii) and (iii).) The issued permit also requires specific recordkeeping related to emissions of sulfuric acid mist. (See new Condition 2.1.10(c)(i) and revised Condition 2.1.10(c)(v).) As related to emissions of sulfuric acid mist, proper operation of the oxy-combustion boiler on an ongoing basis, including periods of startup, shutdown and malfunction, is very effectively addressed by the continuous emissions monitoring that is required on this boiler for SO_2. In fuel combustion devices, SO_2 is a precursor to emissions of sulfuric acid mist. As such, continuous emissions monitoring for SO_2 also serves to address emissions of sulfuric acid mist.

38. The FutureGen 2.0 project would be a major project for emissions of sulfuric acid mist if either one of the unenforceable assumptions about air-firing of the oxy-combustion boiler were removed. For example, if one accepted the Applicant's emission rate of 2.97 lb/hr but calculated potential emissions based on continuous operation, the potential emissions of sulfuric acid mist would be 13 tpy. Less the disputed 3.58 tpy contemporaneous decrease, the net increase would still be 9.4 tpy which is above the significant emission rate for sulfuric acid mist. Similarly, if one accepts the 4800 hour per year limit but corrects the load to the allowable 100 percent while air firing, the potential emissions of sulfuric acid mist would be 15.84 tpy. Subtracting the disputed decrease of 3.58 tpy leaves a net increase of 12.26 tpy, which is also above the significant emission rate.

As already discussed, the issued permit includes limits and other provisions to make enforceable the various elements of the determination of sulfuric acid mist emissions for the proposed project. Accordingly, this comment is no longer relevant.

39. The Applicant did not actually provide the estimates of sulfuric acid mist emissions that it received from the designer of the oxy-combustion boiler, Babcock and Wilcox. (See application, June 2013 submittal, p. 8, fn 3.) However, to the extent these estimates are based on the nominal heat input of 1,605 mmBtu/hr (application, June 2013 submittal, p. 7), they would under-predict potential to emit. In the draft permit, the only enforceable limit on the heat input to this boiler would be 14.5 million mmBtu/yr. (Draft Condition 2.1.6(a).) That limit works out to an hourly maximum heat input of 1,655 mmBtu/hr maximum. (14,500,000 mmBtu/yr ÷ 8760 hrs/yr = 1,655.25 mmBtu/hr).

In response to the discrepancy identified by this comment, the issued permit limits the annual heat in put to the oxy-combustion boiler to 14.1 million mmBtu, rather than 14.5 million mmBtu. This maintains consistency between the limit on the heat input to this boiler set by the permit and the representation of the nominal heat input to this boiler made in the application.

40. In the original permit application (February 2012 submittal, Attachment No. 1), the Applicant stated that emissions of sulfuric acid mist of the oxy-combustion boiler would be 26 tpy when air firing at 45 percent load. Even at 4800 hours/year, that is 14.2 tpy, which would make the project major for emissions of sulfuric acid mist (26 tpy x 4800 hr/yr/8760 hr/yr = 14.247 tpy). The Applicant has not explained why the revised application assumed less sulfuric acid mist emissions.

The issued permit sets limits on emissions of sulfuric acid mist that reflect the current application submittal. When submitting a revised application, an applicant is not required to explain why the emission data in the revised application is different than the previous application. It is commonly recognized that the most recent submittal reflects a more thorough and refined evaluation of the emissions of a proposed project by an applicant than previous submittals. The later submittals may also reflect changes to a proposed project, as is the case for this project. The current application addresses a smaller oxy-combustion boiler, with less capacity, than the boiler addressed in the original application submitted in February 2012.

41. The same basic problems that exist for emissions of sulfuric acid mist also apply to emissions of NOx. In the application (June 2013 submittal, p. 8, Table 3-2), the Applicant claimed the oxy-combustion boiler's NOx emissions in air-firing are 319 lb/hr based on a 45 percent load. However, at the permitted 100 percent load air firing, this would be 708.9 lbs/hr and 3104.9 tpy. (319 lbs/hr x 1.0/.45 x = 708.88 lb/hr, 708.9 lbs/hr x 8760 hrs/yr ÷ 2000 lbs/ton = 3104.93 tpy). Even accepting the Applicant's disputed contemporaneous decrease of 2,813 tpy, the net increase for just the oxy-combustion boiler would be 291.9 tpy which is above the 40 ton per year significant emission rate for NOx. The annual limit in Draft Permit Condition 2.1.6(b) would not be enforceable as a

practical matter because the Draft Permit does not say that the CEMS has to operate all the time and that compliance with the annual limit has to be determined based on NOx emissions during every hour of operation.

As concerns by this commenter with respect to emissions of sulfuric acid mist from this project have been addressed and responded to in the issued permit, the concerns about NOx emissions posed in this comment have also been addressed. Indeed, as the issued permit limits operation of the oxy-combustion boiler in air-firing mode to no more than 4,800 hours per year, the permitted annual NOx emissions from this boiler are now 1,529.9 tpy. The net change in NOx emissions, considering both the increase in emissions from this project and contemporaneous emissions increases and decreases from other projects, is now a decrease of 1,208.4 tpy.[33] As such, the proposed facility is clearly not subject to PSD for NOx.

42. Emissions of fluorides are also above the significance emission rate. The Applicant claims a 0.63 lb/hr emission rate at 45 percent load. (Application, June 2103 submittal, Table 3-2, p. 8). This translates to 1.4 lbs/hr at the permitted 100 percent load. (0.63 x 1/.45 = 1.4). For a full year, 1.4 lbs/hr is equivalent to 6.1 tpy. (1.4 x 8760 ÷ 2000 = 6.132). This is above the significant emission rate for fluorides, 3.0 tpy. The Applicant did not claim that there was a contemporaneous decrease so the new boiler also triggers PSD for fluorides.

The proposed project is not subject to PSD for fluorides. The provisions that have been added to the issued permit in response to comments concerning the limits in the draft permit for emission of sulfuric acid mist also serve to respond to this comment. In particular, the issued permit appropriately restricts the load at which the oxy-combustion boiler may be operated. It also limits operation of this boiler in air-firing mode to no more than 4,800 hours per year. Indeed, with this operational limit, the issued permit now limits annual emissions of fluorides to 1.6 tpy.[34] This is well below the significant emissions rate for fluorides, 3.0 tpy.

Moreover, as observed by this comment, netting was not conducted for fluorides, i.e., the decreases in fluoride emissions from the shutdown of the existing boilers were not considered by the Applicant when determining applicability of PSD. If decreases in fluoride emissions were considered, the net increase in fluoride emissions would be less than 1.6 tpy.

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[33] **Based on operation in a mode other than oxy-combustion for no more than 4800 hours per year, the permitted NOx emissions of the oxy-combustion boiler are 1529.9 tpy. The net change in NOx emissions from the project, also considering the NOx emissions of the auxiliary boiler and the engine at the sequestration site, the contemporaneous increase from the existing emergency engine, and the contemporaneous decreases in emissions from existing boilers, is a net decrease of 1208.4 tpy. (1529.9 tpy + 41.6 tpy + 1.1 tpy) + 32 tpy - 2813 tpy = - 1208.4 tpy.**

[34] **Based on operation in a mode other than oxy-combustion for no more than 4800 hours per year, the permitted fluoride emissions of the oxy-combustion boiler are now 1.6 tpy.**
{(0.63 lbs/hr x 4800 hrs/yr) + (0.05 lbs/hr x 3960 hr/yr)} ÷ 2000 lbs/ton = 1.6 tpy.

43. The emission limit for fluorides in Draft Condition 2.1.6(b) would not change the conclusion of my analysis. The Draft Permit would not require any monitoring, testing or reporting for fluorides. Thus, the fluorides emission limit is not federally or practically enforceable and therefore does not impact the potential to emit calculation. See 40 CFR 52.21(b)(4).

In response to this and other comments, upon further consideration, the issued permit requires initial testing of the oxy-combustion boiler in both oxy-combustion and air-firing modes for emissions of fluorides (See Conditions 2.1.7(c)(i), (ii) and (iii)). It is not unreasonable for this testing to be required. With the restriction in the issued permit on operation of this boiler in other than oxy-combustion mode, the permitted emissions of fluorides from this boiler, 1.6 tons per year, are still more than 50 percent of the significant emission rate for fluorides.

The issued permit also specifically requires recordkeeping for emissions of fluorides (See revised Condition 2.1.10(c)(iv).) Finally, as related to emissions of fluorides, proper operation of the oxy-combustion boiler on an ongoing basis is addressed by the continuous emissions monitoring that is required on this boiler for SO_2 and PM.

44. The proposed project, FutureGen 2.0, triggers PSD for all pollutants but SO_2 and $PM_{10.}$ This is because the Applicant's netting analysis incorrectly used a baseline for calculating the emission decreases from the shutdown of Boilers 1 through 6 that is more than five years prior to commencing construction on the project. The Applicant used baselines for calculating the decreases from the boilers that ranged from March 2007 to February 2009. However, the Applicant indicates it intends to commence construction in July 2014. (See Draft Permit, Table 1B, Note A.) Thus, the baseline period can begin no earlier than August 2009. 40 CFR 52.21(b)(3)(i)(B) states baseline "actual emissions for calculating increases and decreases under this paragraph (b)(3)(i)(b) shall be determined as provided in paragraph (b)(48) of this section, except that paragraphs (b)(48)(i)(c) and (b)(48)(ii)(d) of this section shall not apply."

40 CFR 52.21(b)(48)(i) provides the baseline is 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**.
>
> 40 CFR 52.21(b)(48)(emphasis added).

In the application (June 2013 submittal, p. 17), the Applicant claims, without any citation, that "US EPA has determined that the baseline period for contemporaneous emissions changes is based on the date the change occurred." This claim contradicts the plain language of 40 CFR 52.21(b)(48) which says the baseline for contemporaneous increases and decreases is "*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***." The plain language controls. Thus, the baseline period can thus start no earlier than August 2009, which is five years prior to when the Applicant will begin actual construction. (See application, June 2013 submittal, Form 240-CAAPP for the oxy-combustion boiler, p. 1 of 11.)

The emissions decreases from the shutdowns of Boilers 1 through 6 were appropriately determined in accordance with the PSD rules and USEPA guidance, including USEPA's *New Source Review Workshop Manual,* draft 1990 (NSR Manual). This comment incorrectly assumes that there is only one project for purposes of netting so that the "baseline period" and the "contemporaneous period" are identical. However, the netting analysis for the proposed facility actually involves several projects.[35] The first project is the construction of the proposed facility. The shutdowns of the existing boilers are separate projects, which occurred when the various boilers were shutdown.[36] Thus the "baseline periods" or the periods that may be used to determine the emissions decreases from the shutdowns of Boilers 1 through 6 are different than the five year contemporaneous time period for netting.[37]

The contemporaneous period is determined from the timing of the proposed project for which netting is being conducted, in this case, the proposed modification of the Meredosia Energy Center, including the construction of an oxy-combustion boiler.[38] As provided by 40 CFR 52.21(b)(3)(ii), the contemporaneous period begins "…five years before the date that construction on the particular change commences." All increases and decreases in emissions that occur in this contemporaneous period must be included in the determination of a net emission increase under 40 CFR 52.21(b)(3)(i).

On the other hand, the baseline period for decreases in emissions from other projects during the contemporaneous period for a proposed project is governed by the definition of baseline actual emissions, 40 CFR 52.21(b)(48), and the specific timing of those other projects. For changes in emissions at electrical steam generating units, 40 CFR 52.21(b)(48)(i) provides that the baseline period is any consecutive 24 month period in the 5 year period that precedes a project.[39] The

[35] As defined by 40 CFR 52.21(b)(52), "*Project* means a physical change in, or change in the method of operation of, an existing major stationary source."
[36] The installation of the existing diesel fired emergency generator is also a separate project.
[37] The appropriate emissions baseline is also distinct from the baseline period for determining the increase resulting from the modification of an existing emission unit.
[38] Using the terminology of the PSD rules, 40 CFR 52.21(3)(i)(a), the project that determines the contemporaneous time period is the "…particular physical change or change in the method of operation at a stationary source." That is, it is a project for which netting is conducted to show that, notwithstanding the fact that the increase in emissions of a pollutant from such project is significant, the net increases in emissions of the pollutant, considering contemporaneous increases and decreases, is not significant.
[39] The baseline period for emission units other than electrical steam generating units is governed by 40 CFR 52.21(b)(48)(ii). The baseline period for these other types of units generally extends back 10-years, i.e., "…

provisions for the baseline period for a shutdown are no different than the provisions that apply for other projects that can result in decreases in emissions, such as the additional of control equipment or a process change that acts to lower emissions. The baseline period is the period preceding the particular change.[40] Accordingly, the baseline periods for the shutdowns of the existing boilers at the Meredosia Energy Center are set by the timing of these shutdowns. The baseline periods for these emissions decreases are not set by the timing of the proposed project, which only governs whether these decreases are contemporaneous.

This approach to netting under the PSD rules is confirmed by USEPA in the NSR Manual. In particular, the NSR Manual, pp. A.46 through A.50, describes a procedure for netting in which the determination of the contemporaneous period (Step 2) is a separate step from the determination of creditable emissions increases and decreases (Step 5). In addition, the baseline period for decreases in emissions need not be within the contemporaneous period that determines whether a decrease in emissions is contemporaneous. The NSR Manual, p. A.49 and Figure A.2, provides a specific example of netting in which the baseline period extends back beyond the contemporaneous time period, as is the case for the proposed FutureGen 2.0 project.[41, 42]

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any consecutive 24 month period selected by the owner of operator within the 10-year period immediately preceding either the date the owner of operator begins actual construction of the project, or the date a complete application is received …"

This provision for other units would have no purpose if the baseline period for netting were always constrained to the contemporaneous period, as claimed in this comment. For this provision to have meaningful effect, baseline periods and contemporaneous periods must necessarily be different.

[40] It would not be logical for the baseline period for these changes to be determined using a different date that would is governed by the date of a future project for which netting would be relied upon.

[41] USEPA prepared the NSR Manual prior to the revisions to the PSD rules that occurred as part of "New Source Review Reform," including the adoption of the definition of baseline actual emissions, 40 CFR 52.21(b)(48). As such, the NSR Manual addresses an earlier version of the PSD rules in which the baseline period for netting was governed by the definition of actual emissions, 40 CFR 52.21(b)(21) and was generally the 24-month period prior to a change. The subsequent changes to the provisions of the PSD rules that govern the baseline period, with the adoption of 40 CFR 52.21(b)(48), affected how the baseline period is determined. These changes did not alter the fact, as confirmed by the cited example of netting in the NSR Manual, that the contemporaneous period and baseline periods are different and that a baseline period can extend back beyond the contemporaneous period.

[42] The fact that the baseline period and the contemporaneous period are different and that the baseline for a shutdown is determined by the timing of the shutdown is also confirmed by the USEPA guidance cited elsewhere by this commenter, Memorandum, "Proposed Netting for Modifications at Cyprus Northshore Mining Corporation, Silver Bay, Minnesota," from John Calcagni, Director, Air Quality Management Division, USEPA, to David Kee, Director, Air and Radiation Division, USEPA Region V, August 11, 1992. In this memorandum, USEPA addresses whether certain emission decreases from past shutdowns at a source can be included in a netting analysis for a proposed project at the source.

USEPA first concludes that the emission decreases are not contemporaneous because the shutdown of the existing operations occurred outside of the contemporaneous period for the proposed project. USEPA continues with a discussion of the amount of the emission decreases that accompanied the shutdown of the existing operations, hypothetically assuming that the shutdowns were contemporaneous. For this purpose, USEPA considered the actual decreases in emissions from the shutdowns using a baseline determined from the assumed date that the shutdowns occurred, not from the timing of the proposed project and the

45. If the proper baseline is used for the proposed project, there are only creditable emissions decreases from the shutdown of Boilers 5 and 6 at the Meredosia Energy Center. Using the proper baseline, my analysis shows that the project will have significant net emission increases for NOx, $PM_{2.5}$, and GHG. My calculations, as follow, rely on the project's potential emissions from the Draft Permit, Attachment 1, Table 1B, and on data from 2009 and 2010 that I obtained from USEPA's Clean Air Markets database. I excluded the emergency engine-generator permitted in 2008 as this was before the baseline period. I accepted the Applicant's calculations of potential emissions for the sake of this analysis even though I dispute these calculations in my other comments. For example, using the proper baseline, for emissions of NOx, the creditable decrease in emissions from the shutdown of the boilers at the Meredosia Energy Center is 882 tpy (average annual NOx emissions of Boilers 5 and 6 from 2009 and 2010). The net increase in emissions is 852 tpy (1,734.4 tpy - 882 tpy = 852 tpy). This net increase is far above the significant emission rate for NOx, 40 tpy. For $PM_{2.5}$, using the Draft Permit's emission factor, use of the proper baseline results in a creditable decrease of 72 tpy (average annual $PM_{2.5}$ emissions of Boilers 5 and 6 calculated from operation in 2009 and 2010). The net increase in emissions is 25 tpy (97 tpy - 72 tpy = 25 tpy). This is above the significant emission rate for $PM_{2.5}$, 10 tpy.[43]

This comment does not show that the proposed project is subject to PSD for emissions for NOx, $PM_{2.5}$, and GHG. As already discussed, a proper baseline period, consistent with 40 CFR 52.21(b)(48)(i), was used to determine the emission decreases from the shutdown of the existing boilers at the Meredosia Energy Center. The Applicant used the same 24-month period, March 2007 through February 2009, to determine the emission decreases from the shutdowns of Boilers 1 through 4 and Boilers 5 and 6. These 24-months are within the five year period preceding November 9, 2009, the date on which Boilers 1 through 4 were was removed from service. These 24-months are also within the five year period preceding January 1, 2012, the date on which Boilers 5 and 6 were removed from service. The fact that a later 24-month period, as used by this commenter, yields smaller decreases in emissions from the shutdown of the existing boilers does not show that the Applicant improperly determined these emissions decreases.[44]

contemporaneous period. As such, this guidance also confirms that the emissions decreases from the shutdown of a unit are to be determined based on the timing of the shutdown. (In the particular case that was being addressed, USEPA concluded that there were no creditable emission decreases from the shutdowns. This was because the existing operations had not operated and had no emissions during the relevant baseline period.)

[43] Similarly, the use of the proper baseline for CO_2 results in a creditable decrease of 935,848 tpy (average annual CO_2 emissions of Boilers 5 and 6 from 2009 and 2010). The net emissions increase is 586,655 tpy (1,522,503 tpy - 935,848 tpy = 586,655 tpy). This exceeds the 75,000 tpy significant emission rate for GHG to an extent that easily covers any potential creditable decrease from N_2O and methane that may not have been included in the Applicant's calculation.

[44] **Incidentally, with the reduction in permitted $PM_{2.5}$ emissions that have been made in the issued permit, which reduce the proposed project's $PM_{2.5}$ emissions to 66.1 tpy, the project would still not be significant for $PM_{2.5}$ even using the baseline period for Boilers 5 and 6 that this commenter used.**

46. FutureGen 2.0 modeling shows that the proposed facility would violate the 1-hour SO_2 and NO_2 NAAQS.[45] Therefore, FutureGen 2.0 cannot net out of PSD. As explained by USEPA when discussing a modification proposed by Cyprus Northshore Mining Corporation,

> The PSD rules restrict the creditability of some decreases in emissions for the purpose of emissions netting. In particular, one provision allows credit for a decrease only to the extent that it has approximately the same qualitative significance for public health and welfare as the increase from the proposed change [see 40 CFR 52.21(b)(3)(vi)(c)]. Where there is reason to believe that the reduction in ambient concentrations from the decrease will not be sufficient to prevent the proposed emissions increase from causing or contributing to a violation of any NAAQS or PSD increment, this provision requires an applicant to demonstrate that the proposed netting transaction (despite the absence of a significant net increase in emissions) will not cause or contribute to such a violation (see 54 FR 27298). Even if EPA found the proffered reductions otherwise quantitatively acceptable in this case--where the existing emissions units have not contributed to ambient concentrations for the last 10 years -- Cyprus would have to perform sufficient air quality modeling to demonstrate that the emissions increase from the new units would not violate the applicable NAAQS and PSD increments before the reductions could be credited (see 54 FR 27298).
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> Memorandum, Aug. 11, 1992, from John Calcagni, USEPA, to David Kee, USEPA, re: Proposed Netting for Modifications at Cyprus Northshore Mining Corporation, Silver Bay Minnesota, p. 6

The Applicant tries to excuse its violations of the NAAQS by claiming that because its contribution to the modeled NAAQS violations was below what it claims is the significant impact level, there is no problem. However, the U.S. Court of Appeals for the District of Columbia has recently rejected the use of significant impact levels (SIL). See Sierra Club v. EPA, 705 F.3d 458 (D.C. Cir. 2013).

Moreover, even before that decision, USEPA had determined that if a source causes any NAAQS violations, regardless of the level of contribution, the violation cannot be forgiven. The Applicant failed to do any such analysis.

The position taken in this comment is contrary to sound, well-established practice for air quality analysis for proposed projects. While air quality analyses was not required for this project under the PSD rules, the Applicant conducted air quality modeling to confirm that the project would be appropriately designed so as to not cause or contribute to a violation of the relatively new one-hour NAAQS for SO_2

[45] Refer to Memorandum, August 24, 2013, Steven King, Illinois EPA, Air Quality Planning Section, Modeling Unit, to Bob Smet, New Source Review Unit, BOA Permits, *FutureGen2.0 Repowering Project at the Meredosia Energy Center* (King Memorandum), pp 6 -7.

and NO_2.[46] These analyses demonstrate that the proposed facility will not cause or contribute to such violations without considering the compensating impacts of the contemporaneous decreases in emissions on air quality. Accordingly, it is not reasonable to expect that the net change in emissions, considering both increases and decreases in emissions, will cause or contribute to such violations. This comment certainly does not make this showing.

Moreover, the NSR Manual, pp. A.38 and A.39 (emphasis added) states:

> **Reductions must be of the same pollutant as the emissions increase from the proposed modification and must be qualitatively equivalent in their effects on public health and welfare to the effects attributable to the proposed increase. Current EPA policy is to assume that an emission decrease will have approximately the same qualitative significance for public health and welfare as that attributed to an increase, unless the reviewing agency has reason to believe that the reduction in ambient concentrations from the emissions decrease will not be sufficient to prevent the proposed emission increase from causing or contributing to a violation of any NAAQS or PSD increment. In such cases, the applicant must demonstrate that the proposed netting transaction will not cause or contribute to an air quality violation before the emissions reduction may be credited.**

FutureGen 2.0 emission decreases are of the same pollutants (i.e., SO_2 and NOx) and from the same source category (i.e., coal-fired utility boiler). The permitted NOx emissions of the facility are less than 65 percent of past actual emissions. The SO_2 emissions will be less than 5 percent of the past actual emissions.

Finally, the 2013 decision of the District of Columbia Circuit Court cited by the comment does not address the use of SILs for SO_2 and NO_2 and is not applicable to this action. Even if it were applicable, the use of SO_2 and NO_2 SILs in the air quality analyses for the proposed facility was appropriate under the principles for use of SILs for $PM_{2.5}$ discussed in that decision and in subsequent USEPA guidance regarding that decision. "Circuit Court Decision on $PM_{2.5}$ Significant Impact Levels and Significant Monitoring Concentration, Questions and Answers," USEPA, March 4, 2013. *Sierra Club v. EPA*, 705 F.3d 458, 465 (D.C. Cir. 2013). "We agree that the parts of the EPA's rule codifying SILs in §51.165(b)(2) should remain."

[46] The comment's reference to the King Memorandum, a memorandum prepared by Steven King of the Illinois EPA, to support of its assertion that FutureGen 2.0 modeling shows that the proposed facility would violate the 1-hour SO_2 and NO_2 NAAQS is disingenuous. In fact, this memorandum states that for each 1-hour NOx NAAQS exceedance, "the model predicted results that demonstrated that FutureGen impacts coincident with the time and location of NAAQS exceedances, were below the significance level." For the 1-hour SO2 NAAQS, this memorandum states "the model results showed that Future Gen's worst case contribution to a NAAQS exceedance was 13% of the SIL." (King Memorandum, pp. 6-7).

47. The modeling determined there would be NAAQS violations even though the modeling was not conservative, that is, it under-predicted violations or ignored violations. For example, the application (Application June 2013 submittal, p. 29) indicates that the Applicant only modeled the oxy-combustion boiler air firing as “low power operations,” which I assume is limited to 45 percent load based on the assumptions about air-firing that the Applicant made in calculating potential emissions. However, as explained in my other comments, the draft permit would allow the oxy-combustion boiler to operate in air-firing mode outside of startups and shutdowns. Thus, NO_2 and SO_2 modeling must be done for air-firing at 100 percent load. This is particularly important because a mere four or eight hours of emissions per year can cause NAAQS violations of the 1-hour NAAQS.

As already discussed, the permit establishes enforceable limits for the maximum emissions from different modes of operation of the oxy-combustion boiler. These limits apply independently of the operating load of the boiler. As such, contrary to the claim in this comment, the modeling used appropriate emissions rates for the different modes of operation of the oxy-combustion boiler. In particular, the modeling for air-firing was based on the maximum hourly emission rates that have been set in the permit for air-firing.

48. The Applicant did not model the haul roads or new emergency diesel generator at the sequestration site and the existing emergency engine generator at the Meredosia Energy Center and coal pile fugitives for PM_{10} and $PM_{2.5}$. There are new haul roads and also there is much more activity on the haul roads as trona and lime were not used on site and the ash used to be disposed of on-site rather than being hauled off-site. (Application, June 2013 submittal, p 5). In modeling the haul roads, the Applicant must use worst day emissions which I provided in the Stamper Evaluation.

This comment does not show the modeling should be conducted for the proposed project for PM_{10} and $PM_{2.5}$, much less that modeling should be conducted in the manner suggested by this comment. The net emissions increases from this proposed project for PM_{10} and $PM_{2.5}$ are below the respective significant emission rates and, consequently, this project is not a major project subject to PSD for these pollutants. As such, air quality impact analyses for PM_{10} and $PM_{2.5}$ are not required for the permitting of this proposed project. The circumstances of this proposed project for PM_{10} and $PM_{2.5}$ do not otherwise justify such modeling. In this regard, the project, is a new, modern coal-fired power plant in a rural, attainment area, and should not be expected to pose a direct threat to air quality for either PM_{10} or $PM_{2.5}$.[47]

[47] The circumstances of the proposed project for PM_{10} and $PM_{2.5}$ are different than those for SO_2 and NO_2, for which new NAAQS that apply on a shorter, 1-hour averaging time were recently adopted by USEPA. It is difficult to evaluate the impacts of a proposed power plant on these new NAAQS absent modeling. Accordingly, the Illinois EPA used its discretionary authority to require the Applicant to prepare air quality analyses for the proposed project to address these new one-hour NAAQS. These analyses confirmed that the proposed project would not cause or contribute to any NAAQS violations even without taking into account contemporaneous decreases in emissions and their ensuing positive impact on air quality.

49. There are numerous provisions of the draft permit that would not be federally enforceable or enforceable as a practical matter. For example, the PTE for lead was based on emission factors from USEPA's *Compilation of Air Pollutant Emission Factors*, AP42. VOM was based on vendor estimates. (Application, June 2013 submittal, p. 8, fns 8 and 4). The draft permit would not require any testing to confirm these emission factor estimates are not actually exceeded. Thus, the claim that the source is minor for these pollutants is not enforceable. In order to make these enforceable, the permit needs to require continuous emission monitoring systems (CEMS) or annual stack testing at various loads and all operating scenarios including air firing coupled with parametric monitoring.

This comment does not show that emission testing of the oxy-combustion boiler for lead is needed to make the permit limits enforceable. The total permitted lead emissions from the project are only 0.154 tpy. This is well below the significant emission rate for lead, 0.6 tpy, without consideration of any decreases in lead emissions from the shutdown of the existing boilers. The oxy-combustion boiler will be the only significant source of lead emissions at the facility. As lead is a HAP, emissions of lead from this boiler are addressed by the NESHAP for Coal- and Oil-Fired Electric Utility Steam Generating Units, 40 CFR 63 Subpart UUUUU. The relevant requirements of this NESHAP that apply to this boiler will reasonably ensure compliance with the emission limits that are set by the permit for lead. In this regard, during the development of this NESHAP, USEPA found that filterable PM is appropriately used as a surrogate for non-mercury metal HAPs, including lead.[48, 49] That is, a NESHAP standard set in terms of filterable PM also serves to appropriately limit emissions of non-mercury metal HAPs to levels that are comparable to the alternative standards in the NESHAP for individual non-metal HAPs. For emissions of lead, this alternative standard is 0.02 lb/GWhr.[50] Based on this standard, the lead emissions of the oxy-combustion boiler should be expected to

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[48] For new coal-fired steam generating units, the NESHAP, 40 CFR 63 Subpart UUUUU, contains three alternative standards to address metal HAPs other than mercury: 1) A standard that is expressed in terms of filterable PM; 2) A standard for the total emissions of ten metal HAPs, including lead; and 3) Individual standards for ten metal HAPs, including mercury.

It is expected that most sources, including this source, will elect to comply with the standard for filterable PM.

[49] In this NESHAP, USEPA found it appropriate to set a standard in terms of filterable PM, with filterable PM serving as a surrogate for non-mercury metal HAPs. Among other things, for sources that elected to comply with such a standard, continuous particulate emission monitoring could be required as the means to demonstrate ongoing compliance with the standard. Continuous emission monitoring would not be possible if only standards for total and individual non-mercury metal HAPs were adopted.

[50] As explained by USEPA in the preamble to the adoption of 40 CFR 63 Subpart UUUUU,

> **Except for Hg, the best PM controls provide the best control of metal emissions. Emissions measurements of either filterable particulate, total particulate, individual metals, or total metals provide comparable indications that the best level of control is achieved. We can find no significant difference in the emissions that would be achieved by using any of these emissions measurements.**
>
> **77 FR 9402, Feb. 16, 2012.**

be no more than 0.0145 tpy.[51] This is a fraction of the annual limit that has been conservatively set by the permit for the lead emissions of lead from this boiler. Moreover, the permit, Condition 2.1.7(c), requires the source to conduct emission testing for the oxy-combustion boiler upon request from the Illinois EPA, as specified in such a request. This provides for emission testing for lead in the event that information arises that indicates that such testing is warranted for this boiler notwithstanding the requirements for PM emissions.

This comment also does not show that emission testing of the oxy-combustion boiler for VOM is needed to make the limits on VOM emissions enforceable. The total permitted VOM emissions from the project are only 12.0 tpy. This is well below the applicable significant emission rate for VOM, 40 tpy. The results of emission testing of coal-fired utility boilers for organic emissions indicate that the oxy-combustion boiler should readily comply with the limits that have been set by the permit for VOM emissions.[52] However, test data is not available for a coal-fired utility boiler with oxy-combustion technology. Because of the absence of such data, it is not unreasonable for initial testing for VOM emissions to be required. Accordingly, the issued permit (Condition 2.1.7(a)) also requires that the initial emission testing for the oxy-combustion boiler include measurements for VOM emissions. It is not appropriate for further testing requirements for VOM emissions to be established before this testing is conducted. This is because this testing may show that the VOM emissions of this boiler with oxy-combustion technology are similar to those of boilers using conventional combustion technology.[53]

50. For the oxy-combustion boiler, CH_4 and N_2O PTE were from default emission factors from the 40 CFR Part 98, the Mandatory Greenhouse Gas Reporting Rule. (Application, June 2013 submittal, p. 8, fn 6). The permit needs adequate testing for these to confirm. The Draft Permit would only require one time testing. That is not enough.

This comment does not show that the permit should require additional testing of the oxy-combustion boiler for emissions of CH_4 and N_2O.[54] As observed by this comment, the initial emission testing required for the oxy-combustion boiler must

[51] 0.02 lb/GWhr x 0.165 GWhr x 8760 hrs/yr ÷ 2,000 lbs/ton = 0.0145 tpy.

[52] In its development of 40 CFR 63 Subpart UUUUU, the USEPA concluded that regulation of organic HAPs with numerical standards under Section 112(d) of Clean Air Act was not practical. This was because most of the test data for emissions of organic HAPs and volatile organic compounds assembled by USEPA pursuant to its Information Collection Request for the development of this rule showed emissions that were below the detection levels of applicable test methods even with long durations for test runs. As a result, USEPA decided not to set numerical limits for emissions of organic HAPs. Instead, USEPA set work practice standards (i.e., requirements for periodic combustion tune-ups) under Section 112(h) of the Clean Air Act. *See* 77 FR 9304, 9369 (February 16, 2012).

[53] In this regard, the permit, as already discussed, requires the source to conduct emission testing for the oxy-combustion boiler upon request from the Illinois EPA, as specified in such a request. This provides for emission testing for VOM in the event that the initial testing for VOM emissions indicates that further testing for VOM emissions is warranted for this boiler during the period before a CAAPP permit is issued that addresses this new facility.

[54] Methane (CH_4) and nitrous oxide (N_2O) are compounds that are regulated as greenhouse gases (GHG).

include measurements for emissions of CH_4 and N_2O. This will provide information that is needed to determine whether further testing for these pollutants should be required for this boiler and the timing and other aspects of any such further testing.[55] In this regard, Condition 2.1.7(c)(ii)(b) requires that, upon request by the Illinois EPA, the source must conduct additional emission testing for the oxy-combustion boiler for pollutants as specified by the Illinois EPA.

As a more general matter, the approach to the GHG emissions of the oxy-combustion boiler in the permit is consistent with the approach that has generally been taken by USEPA in its current rules dealing with quantification of GHG emissions from coal-fired boilers. USEPA generally requires continuous monitoring for emissions of CO_2. Emissions of CH_4 and N_2O may be determined using either unit-specific emission factors developed from emission testing or generic emission factors. As reflected by the provisions of 40 CFR 98, USEPA has found that this approach reasonably addresses the contribution of CH_4 and N_2O to GHG emissions of coal-fired boilers, as CO_2 makes up most of the GHG emissions.

51. The permit must require commencement of construction by not later than August 2014 in order for the Applicant's claim of contemporaneous emission decreases, which I dispute, to be valid under the Applicant's own theory. This is because the last time Boilers 1 through 4 had emissions was August 2009.[56]

As requested by the comment, a condition has been added to the issued permit to maintain consistency with the netting analysis that was prepared for this proposed facility. New Condition 1.2(a) provides that the permit will expire if construction of this facility is not commenced by August 2014. This will act to explicitly require construction of this facility to commence by August 2014, as specifically requested by this comment, so that the emission decreases from the shutdown of Boilers 1 through 4 will be contemporaneous with this project.

52. NOx and SO_2 monitoring must apply all the time for netting to be valid including during startups, shutdowns and malfunctions. Alternative monitoring or NSPS monitoring is not sufficient as it does not require emission data from every hour of operation.

The continuous emission monitoring systems required by the permit must be operated "continuously," consistent with the provisions of the NSPS, 40 CFR Part 60, the NESHAP, 40 CFR Part 63, and the Acid Rain Program, 40 CFR Part 75, as applicable. The relevant provisions in these rules do not provide that continuous emission monitoring do not need to be operated during startup, shutdown and

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[55] **As addressed in other comments, the limit for the annual emissions of the oxy-combustion boiler is extraordinarily conservative. This is because it reflects calculations of potential GHG emissions from this boiler without any consideration for sequestration of CO_2. However, demonstration of CO_2 sequestration technology is an essential aspect of the operation of proposed facility. As such, the permitted GHG emissions of this boiler are much greater than the actual emissions would ever be. These circumstances will not be altered by any contribution of CH_4 and N_2O to the GHG emissions of the oxy-combustion boiler.**

[56] See data for the Meredosia Energy Center from USEPA, on its Clean Air Markets Division's internet site.

malfunction of emission units. These rules reasonably and appropriately address proper operation of monitoring systems. For example, 40 CFR 75.10(d), which applies for continuous monitoring of SO_2, NOx and CO_2 emissions of the oxy-combustion boiler only provides that monitoring systems do not have to be operated during periods of calibration, quality assurance, or preventative maintenance, periods of repair, periods of backup of data and during recertification of monitoring equipment.

Incidentally, "proper continuous monitoring" is not needed for the reason given by this comment. Given the magnitude of emission decreases and the basis upon which permitted emissions of the proposed facility were determined, less rigorous emissions monitoring would be sufficient to ensure that this project is not a major project for emissions of NOx and SO_2. Proper monitoring is required as it is required by rule to verify compliance with applicable emissions standards and other regulatory requirements that apply for emissions of NOx and SO_2.

53. The application (June 2013 submittal, p. 4 and p. 27, fn 13)) states that the auxiliary boiler will use ultra low sulfur diesel oil containing 15 ppm sulfur. However, Condition 2.2.3-1(a)(iii)(A) of the draft permit would only limit the sulfur content of the oil fired in this boiler to 5000 ppm. The permit needs to limit the sulfur content of this oil to 15 ppm, as well as require monitoring, recordkeeping and reporting to make this limit enforceable as a practical matter. This includes provisions to ensure that the source does not use diesel currently on site that is above 15 ppm sulfur or transmix diesel.

The issued permit includes additional requirements in response to the concerns identified in this comment. The issued permit explicitly requires that the fuel fired in the auxiliary boiler be ultra-low sulfur diesel (maximum sulfur content of 15 ppm). (See Condition 2.2.5(b)(ii)). As a consequence, this boiler is prohibited from firing any diesel oil that may currently be held at the Meredosia Energy Center that is not ultra-low sulfur diesel fuel. Use of "transmix" or off-specification mixes of ultra-low sulfur diesel and other petroleum products, which would not qualify as ultra-low sulfur diesel fuel, is also prohibited.

The related compliance provisions in the permit for the auxiliary boiler have been enhanced to address this new requirement. The relevant conditions in the issued permit now generally address all requirements for the sulfur content of the fuel for this boiler, including the requirement that it be ultra-low sulfur diesel fuel, as well as the requirements of the NSPS for the sulfur content of this fuel. (See Condition 2.2.8-1 and 2.2.9(a)(i).)

54. The application (June 2013 submittal, Attachment No. 11) claims that the oxy-combustion boiler will have a total HAP emission of no greater than 1.09 lb/hr at all times including startup, shutdown and malfunction. Therefore, the permit needs a total HAP emission limit of 1.09 lb/hr that applies at all times including startup, shutdown and malfunction. The permit should also include a HAPs CEM which monitors hydrogen chloride (HCL) and other HAPs at all times including during startup, shutdown, and

malfunction. This is critical because the uncontrolled emission factor in AP-42 for HCl is 1.2 lb/ton. This means that burning a mere 16,666 tons of coal in the oxy-combustion boiler uncontrolled would put the source over the 10 tons per year major source threshold for an individual HAP.

This comment does not demonstrate that additional limits should be placed on the HAP emissions of the oxy-combustion boiler. The emissions of HAPs from this boiler are regulated by the National Emission Standards for Hazardous Air Pollutants (NESHAP) from Coal and Oil-Fired Electric Utility Steam Generating Units, 40 CFR 63 Subpart UUUUU. The various requirements of this rule that are applicable to this boiler will act to ensure that its annual emissions do not exceed the limits for emissions of HAPs set in Condition 2.1.6(b), 4.5 tpy for any individual HAP and 19.86 tpy for total HAPs. Given that emissions of HAPs are regulated by 40 CFR 63 Subpart UUUUU, it is not appropriate for the permit to set additional short-term limits for emissions of HAPs or to include additional compliance procedures related to HAPs beyond those in this NESHAP.

Additional permit requirements certainly are not justified because of the magnitude of "uncontrolled" emissions of HCl, as suggested by this comment. The control systems on the oxy-combustion boiler for SO_2 emissions will also control HCl emissions. Emissions will specifically be restricted by the NESHAP, which limits HCl emissions to 0.010 lb/MWh, either directly or through compliance with a limit for SO_2 of 1.0 lb/MWh. This will necessitate HCL emissions being controlled so that actual emissions are a fraction of uncontrolled HCl emissions, as would be determined using the emission factor in AP-42 cited by this comment.

55. The application (June 2013 submittal, Attachment No. 2) assumes 95 percent control for two transfer points for the coal handling equipment: (1) Conveyor C to Chain Conveyor and, (2) Chain Conveyor to Coal Silos. Therefore the permit must have emission limits, testing and monitoring to ensure that these emission limits, that is, 0.85 lb/hr PM, 0.38 lb/hr PM_{10} and 0.0425 lb/hr $PM_{2.5}$ for each of these transfer points, is not exceeded. In addition, the permit must require there be zero fugitive emissions from these transfer points and monitoring, testing and reporting to ensure compliance with the absolute restriction on fugitives from the transfer points.

In response to this comment, changes have been made in the issued permit to enhance the practical enforceability of the emission limits for the new and modified coal handling operations. In particular, the issued permit now individually limits the emissions of PM and PM_{10}/$PM_{2.5}$ from each of the coal handling operations, rather than limiting the combined emissions of these operations. The permit also sets limits for emissions of each operation expressed in pounds per ton of coal handled. These changes reasonably enhance practical enforceability of the emission limits for these operations. It will be simpler to review compliance of individual operations than to review compliance of the operations in aggregate. It also will be

easier to review compliance with both short-term and annual emission limits than only an annual limit.

However, it is not appropriate for the permit to limit emissions in pounds per hour, as requested by this comment. This is because these operations will not run continuously but periodically to fill the bin that supplies coal to the boiler.[57] It also is not appropriate to prohibit any fugitive emissions from the subject operations, as requested by this comment. This is because the emission limits for the subject operations reflect emissions calculations in the Application that are predicated upon compliance with applicable control requirements of the NSPS, 40 CFR 60 Subpart Y, by the subject operations. This NSPS establishes limits for both "stack" emissions and "fugitive" emissions from coal handling operations. The opacity of fugitive emissions is limited to 10 percent by 40 CFR 60.254(b)(2). As such, it is not necessary for the permit to include the compliance provisions that are specifically requested by this comment.

Moreover, the permit does include compliance provisions that reasonably address the emissions limits that have been set by the permit. The permit generally relies on the applicable requirements of the NSPS to address the initial performance testing for the subject operations and monitoring of their ongoing operation (Condition 2.3.7). The permit also includes appropriate recordkeeping requirements, building on the testing and monitoring requirements of NSPS, to address compliance with the emission limits that have been set for the subject operations. In particular, the issued permit requires records for the maximum emissions rates of the subject operations, in pounds per ton of coal handled, with supporting documentation, to provide an authoritative basis for these emission rates that are used in the determination of compliance with emission limits (Condition 2.3.8(d)(i)). The permit also requires records of actual emissions to directly verify compliance with the applicable emission limits (Condition 2.3.8(d)(ii)).

56. The permit needs to limit the usage of coal by the oxy-combustion boiler to 744,600 tons per year. Many of the emission calculations are based on this assumption for maximum coal usage. The 14.5 million mmBtu/yr limit is important for other calculations but it is not sufficient for all calculations such as the coal transfer equipment and the haul roads. The permit must also include monitoring and reporting to ensure that the 744,600 tons per year of coal limit is enforceable as a practical matter.

In response to this comment, a condition has been added in the issued permit limiting the amount of coal conveyed to the oxy-combustion boiler to 744,600 tons per year. (Condition 2.1.6(a)(ii).) In addition, the recordkeeping requirements for

[57] It is also not necessary to set separate limits for the $PM_{2.5}$ emissions of the subject operations. Limits for $PM_{10}/PM_{2.5}$ will simplify review of the determinations of compliance that are made by the source. Separate, lower emission limits for $PM_{2.5}$ emissions are not needed to ensure that the net increase in emissions of $PM_{2.5}$ from the proposed project is less than significant. Separate limits for $PM_{2.5}$ emissions also would not meaningfully affect the net change in emissions of $PM_{2.5}$ from this project.

this boiler in the issued permit have been enhanced to address compliance with this additional operational limit. (Condition 2.1.10(b)(i).)

57. The application (submittal June 2013, Attachments No. 3, 4 and 5) assumes PM emissions of 0.02 grains per dry standard cubic feet from the ash silo bin vent, lime transfer and trona transfer. The permit needs to have an emission limit of 0.02 grains per dry standard cubic feet for these emission units and monitoring, testing and reporting to ensure this limit is enforceable as a practical matter.

In fact, the limit for the subject operations requested by this comment was included in the draft permit (Draft Condition 2.4.5(a) and is carried over in the issued permit (Condition 2.4.5(a)). The compliance provisions of the permit that address the subject operations and their emissions will generally serve to address compliance with this specific requirement for filters. However, in response to this comment, the recordkeeping for the subject operations has been enhanced. These records must now include a copy of the design specifications for these filters, including the particulate exhaust loading, in gr/dscf. This will provide further confirmation that the source has installed appropriate filters for these operations.

58. The permit needs to limit the trona transfer flow to no more than 700 scfm, the lime flow to 1,500 scfm, and the ash flow to 2,500 scfm, consistent with information used in the emission calculations in the application (submittal June 2013, Attachments No. 3, 4 and 5). The permit needs testing, monitoring and reporting to ensure that these flow limits are not violated. In the alternative, these emission points could have PM CEMs.

This comment does not show that it is appropriate to set limits for air flow capacity of the filters for the subject operations. Limits on air flow capacity would potentially interfere with effective control of particulate emissions as necessary to comply with the emission limits that have been set for these units. The emissions of the subject operations are adequately addressed by the individual limits that have now been set in the issued permit for each of the subject operations.

In addition, PM CEMS are not feasible for the subject operations, much less reasonable or appropriate. The subject operations only involve handling of bulk materials. The amounts of emissions are small. Proper operation of the subject operations and associated control measures and control devices can be reasonably be assured by appropriate work practices and recordkeeping, accompanied by emissions testing as necessary.

59. As to the pugmill to trucks drop point, the application (submittal June 2013, Attachment No. 3) assumes the ash is wetted to 15 percent moisture. The permit must have an enforceable requirement that the ash be wetted to 15 percent moisture content and testing, monitoring and reporting for this requirement.

In response to this comment, the issued permit now limits the moisture content of dry ash from the oxy-combustion boiler as loaded out from the facility, including the dry solids from the circulating dry scrubber, to at least 15 percent by weight. (Condition 2.4.5(b).) To ensure that the 15 percent moisture requirement is met for dry ash, the issued permit requires operational monitoring for the amount of water mixed with the ash. (Condition 2.4.8-1).) This makes this element of the emissions calculations in the application for the ash handling operations enforceable as both a legal and practical matter.

60. The permit must limit the drift flow for the Unit 4 main cooling tower to 0.94 gallons per minute (gpm), for the ASU/CPU cooling tower to 0.23 gpm and the DCCPS cooling tower to 0.16 gpm. (See application, June 2013 submittal, Attachment No. 7). The permit must also limit the total dissolved solids (TDS) to 518 ppm for the Unit 4 main cooling tower, 2090 ppm for the ASU/CPU cooling tower and 7043 ppm for the DCCPS cooling tower. The permit must have testing, monitoring and reporting requirements to ensure these flow rate and TDS limits are not exceeded.

In response to this comment, changes have been made in the issued permit to enhance the practical enforceability of the emission limits for the cooling towers. In particular, the issued permit now individually limits the emissions of PM and $PM_{10}/PM_{2.5}$ from each of the cooling towers, rather than limiting the combined emissions of the cooling towers. These changes reasonably enhance the practical enforceability of the emission limits. Similar to the circumstance of the coal-handling operations, it will be simpler to review compliance of individual cooling towers than to review compliance of the group of three cooling towers, in aggregate. Circumstances have not been identified that would argue against establishment of emission limits for the individual cooling towers.

However, this comment does not show that it is appropriate to set limits for the cooling towers for water flow rates and TDS levels in the water. These operating parameters of the cooling towers, which are relevant to particulate emissions, can be readily determined through the operational monitoring and recordkeeping that is required by the issued permit. This is different than the circumstances of emission units for which actual emissions can only be authoritatively determined by emissions testing. Moreover, limits on water flow rates and TDS levels could inadvertently act to interfere with the proper operation of the DCCPS control system for the oxy-combustion boiler, which relies on cooling from the associated DCCPS cooling tower.[58] Such limits could potentially make compliance with the applicable requirements established for the wastewater discharges from the facility, which are from the blowdown from these cooling towers, more challenging or problematic. Such limits could also unnecessarily interfere with other aspects of the operation of the cooling towers, such as minimization of water consumption and

[58] **The DCCPS cooling tower is necessary for the functioning of the DCCPS which controls the temperature and moisture content of the flue gas stream for the oxy-combustion boiler that is then further processed by the Compression Purification Unit.**

adjustment of operation in response to seasonal variation in the quality of the incoming water. In such circumstances, it is reasonable to rely on limits for the emissions of these cooling towers with operational monitoring and recordkeeping by the source as needed to verify compliance with those limits.

61. The limits for annual emissions of NOx, CO, PM, PM_{10}, $PM_{2.5}$ and GHG for the auxiliary boiler are not enforceable as a practical matter. One time testing tells nothing about annual emissions. While Draft Permit Condition 2.2.9(g)(iii) would require the source to keep records of the emissions of these pollutants in tons/month and tons/year, there is no data for the source to keep these records.

This comment does not show that the emission limits for the auxiliary boiler are not enforceable as a practical matter. As observed by this comment, initial emission testing is required by the construction permit (see Condition 2.2.7-2).[59] It is not reasonable for the specific timing of subsequent emission tests to be addressed in this permit. This is appropriately addressed as part of Periodic Monitoring required for this boiler in the Clean Air Act Operating Permit Program (CAAPP) permit for the new facility.[60] In this regard, add-on control equipment is not present on the auxiliary boiler. As part of the processing of the application for the CAAPP permit, key factors that are relevant to the timing of periodic emission testing, which are not known prior to operation, can be properly considered. In particular, at this time, the magnitude and nature of actual operation of this boiler, on both a short-term and annual basis, are unknown.[61] The results of actual emission testing of this boiler also are not available.[62]

The construction permit includes provisions to reasonably address the day-to-day operation of the auxiliary boiler as this will determine the annual emissions of this boiler. Among other things, the permit addresses the requirements of the NESHAP for periodic tune-ups of this boiler (Condition 2.2.3-1(b)(ii)). It also addresses the requirement of the NSPS for ongoing monitoring of the opacity of the boiler (Condition 2.2.8-2). The permit requires recordkeeping for various aspects of the operation of this boiler, including: fuel usage (Condition 2.2.9(a)(ii)); startups, shutdown and malfunctions (Condition 2.2.9(d)); inspections, maintenance and repair (Condition 2.2.9(e)); and deviations (Condition 2.2.9(f)). The required

[59] In the issued permit, the initial emission testing for the auxiliary boiler must also include measurements for filterable and condensable particulate matter.

[60] The CAAPP is Illinois' operating permit program for sources of emissions pursuant to Title V of the Clean Air Act.

[61] The annual emission limits that have been set for the auxiliary boiler are very conservative. This boiler will support the startup of the oxy-combustion boiler and will normally not be in service. However, the permitted annual emissions of this boiler reflect continuous operation (8760 hours per year).

[62] The construction permit also addresses the possibility that additional emission testing of the auxiliary boiler is warranted in the time before a CAAPP permit is issued that addresses this boiler (e.g., the results of the initial emission testing for this boiler shows a small margin of compliance for a particular pollutant). Condition 2.2.7-2(a)(ii) provides that the source must conduct additional emission testing upon written request from the Illinois EPA.

recordkeeping for emissions includes not only records for annual emissions, but also supporting information, including documentation for the various emission rates and factors that are used to determine annual emissions (Condition 2.2.9(g)(i)) and records of any other operating data that the source uses in determining its annual emissions (Condition 2.2.9(g)(ii)). Additional requirements to address the ongoing operation of this boiler may be included in the CAAPP permit for this new facility considering actual operation of this boiler.

62. For the auxiliary boiler, the initial test for NOx and CO would only be required to be conducted within one year of startup. See Draft Permit Condition 2.2.7-2(a)(i). There is no reason to allow a year of operations to go by before determining initial compliance.

The required timing for the initial emission testing of the auxiliary boiler is appropriate. This boiler will support the startup of the oxy-combustion boiler. Because the auxiliary boiler will not operate routinely, the scheduling of the emission testing for this boiler will be more challenging than for a unit that operates routinely. Accordingly, the permit provides that the initial emission testing required of this boiler must be conducted within one year of initial startup. This is reasonable to address the challenges that will be faced in the scheduling of this testing. This will potentially also enable this testing to be conducted when this boiler would normally be operated, rather than necessitating that it be operated only for the purpose of conducting testing.

63. The Illinois EPA should include terms in this construction permit that require carbon capture. The Illinois EPA's authority and discretion in establishing permit terms and conditions is addressed by 35 IAC 201.156 ("The Agency may impose such conditions in a construction permit as may be necessary to accomplish the purposes of the Act, and as are not inconsistent with the regulations promulgated by the Board thereunder.").

As previously discussed, this project is being developed to demonstrate full-scale oxy-combustion and carbon capture and sequestration (CCS) technologies for a coal-fired electrical generating unit. The development of these technologies is being pursued to reduce the CO_2 emissions of electric power plants, thereby mitigating their contribution to global warming and climate change.

The initial phase of operation of the facility would be specifically designed to evaluate the performance and capabilities of these technologies as installed at this plant. During this time, data would be gathered to facilitate subsequent large-scale commercial projects that rely on these technologies. While the Environmental Protection Act (Act) gives the Illinois EPA authority to establish construction permit terms that are necessary to accomplish the purposes of the Act, this comment does not show how a condition imposing requirements related to CCS is necessary to accomplish the purposes of the Act. Indeed, the project is by its basic nature consistent with the Act. That is, successful implementation of the project will facilitate use of technologies that can reduce CO_2 emissions from power plants and,

potentially, other large sources, with accompanying benefits for the environment due to the resulting reductions in CO_2 emissions.

64. During the public hearing on the draft permit, the Applicant suggested that the definition of a clean coal facility in the Illinois Power Agency Act (Public Act 95-0481) may somehow preclude inclusion of carbon capture requirements in this construction permit. However, the Illinois Power Agency Act does not include any such limitation. The purpose of the Illinois Power Agency Act is to create an independent state agency, the Illinois Power Agency (IPA), to develop and administer electricity procurement plans for investor-owned electric utilities supplying over 100,000 Illinois customers. These plans must include the procurement of cost-effective renewable energy resources. The law also states that "the goal of the State [is] that by January 1, 2025, 25 percent of the electricity used in the State shall be generated by cost-effective clean coal facilities." The Illinois Commerce Commission (ICC) has stated that the law then "set[s] forth a framework for evaluation and approval of certain clean coal sourcing agreements," and "provides that the IPA and the ICC may approve such sourcing agreements, as long as they do not exceed cost-based benchmarks." Re FutureGen Industrial Alliance, Inc., 13-0034, June 26, 2013 (Ill.C.C.).

"Clean coal" facilities are defined in the Illinois Power Agency Act. In relevant part, this law defines a "clean coal facility" as "an electric generating facility that uses primarily coal as a feedstock and that captures and sequesters carbon dioxide emissions at ... at least 70 percent of the total carbon dioxide emissions that the facility would otherwise emit if, at the time construction commences, the facility is scheduled to commence operation during 2016 or 2017…" The definition also limits emissions from such facilities to the "allowable emission rates for sulfur dioxide, nitrogen oxides, carbon monoxide, particulates and mercury for a natural gas-fired combined-cycle facility the same size as and in the same location as the clean coal facility at the time the clean coal facility obtains an approved air permit." 20 ILCS 3855/1-10.

The law does not discuss requirements for "clean coal" construction permits, nor does it limit Illinois EPA's authority with respect to issuing a robust permit in accordance with the purposes of Illinois' Environmental Protection Act. Indeed, there is nothing in the Illinois Power Agency Act suggesting that carbon capture should not also be included in the construction permit. Whether the restrictions included in the Illinois Power Agency Act's definition of a "clean coal facility" are included in any financing, cooperation, or purchasing agreements that the Applicant has entered into should not insulate the air permit from including similar restrictions.

The hearing officer made clear that this permit is governed by Illinois' Environmental Protection Act rather than the Illinois Power Agency Act. At the hearing, he explained: "And I can tell you that our authority to issue permits is not based on the act that you stated, it is based on the Environmental Protection Act." Public Hearing Transcript at 32:9-18.

The Illinois EPA agrees that nothing in the definition of "clean coal facility" as provided by the Illinois Power Agency Act, 20 ILCS 3855, precludes the Illinois EPA from including carbon capture requirements in this construction permit. However, by the same token, nothing in the Illinois Power Agency Act mandates the inclusion of such requirements in this permit. Rather, the Illinois EPA is acting under different authority as provided by the Illinois' Environmental Protection Act, 415 ILCS 5. In particular, the Illinois EPA is guided by Section 39(a) of the Environmental Protection Act, which provides that a permit is to be issued by the Illinois EPA upon proof that a facility will be consistent with the Environmental Protection Act and regulations thereunder. Given the applicant has submitted such proof, the Illinois EPA has taken action to issue the current construction permit.

65. Illinois law does not excuse the Illinois EPA from its responsibility to issue a construction permit for this proposed facility that is compliant with the Clean Air Act.

This is correct. The permit that has been issued for the proposed facility is consistent with the requirements of both state law, i.e., the Environmental Protection Act, and federal law, i.e., the Clean Air Act.

66. New electric utility generating units (EGU) will be subject to the USEPA's proposed NSPS for emissions of carbon dioxide (CO_2), Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units, 40 CFR 60 Subpart TTTT. According to the pre-publication version of USEPA's proposed rulemaking, this NSPS "will apply to both a new, greenfield EGU facility or an existing facility that adds EGU capacity by adding a new EGU that is an affected facility under this NSPS." USEPA, Preliminary Version of Notice of Proposed Rule, Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units, [EPA-HQ-OAR-2013-0495; RL-9839-4], at 310 (September 20, 2013).

This proposed NSPS will soon be formally proposed by USEPA, with publication of a notice of proposed rulemaking in the Federal Register well before construction of the proposed oxy-combustion boiler is commenced. Accordingly, the requirements of this NSPS will apply to the proposed facility.[63] This is because the emission limits in the proposed rule will apply from the date of the proposal once the rule is finalized. Clean Air Act, 42 U.S.C. §§ 7411(a)(2). As a major source of CO_2, as shown above, FutureGen 2.0 will be required to comply with the best available control technology (BACT) for CO_2. The proposed rule establishes limits which will form the "floor" with this requirement. As such, the Illinois EPA should use its discretionary authority to include the proposed rule's CO_2 limits in the permit.

[63] The Illinois EPA indirectly acknowledges this fact in the Project Summary that accompanied the draft permit. The Project Summary states that the requirements of USEPA's NSPS for Greenhouse gas Emissions of Electric Utility Generating Units are not included in the draft permit "because USEPA has not completed this rulemaking." Project Summary, p. 6, fn. 12. The Illinois EPA goes on to state that "the plant would be designed to sequester CO_2, as the USEPA proposed for new coal-fired generating units."

As generally observed by this comment, the proposed facility will in all likelihood be subject to requirements under USEPA's NSPS for emissions of GHG from EGUs, 40 CFR Part 60 Subpart TTTT, which will address emissions of CO_2 from new EGUs once this NSPS is adopted by USEPA. This is because construction on the proposed facility will not commence prior to the publication of the proposed NSPS standard in the Federal Register, which is expected to occur in the near future.[64]

What this comment overlooks, is that the proposed facility will be subject to the requirements of the final NSPS rule as actually adopted by USEPA, after consideration of public comments on the proposed rule and resolution of any legal challenges that may lead to a stay of the rule adopted by USEPA. The proposed facility will not be subject to the requirements of the proposed rule to the extent that the requirements of the final rule differ from the proposed requirements. At present, the actual requirements that the proposed facility will be subject to pursuant to this new NSPS are uncertain. It would be improper in the construction permit to assume that these requirements will be identical to those of the proposed NSPS.[65] Moreover, based on the text of the planned Federal Register Notice, this new NSPS would be based on sequestration of CO_2 from new coal-fired electric generating units. As the proposed facility would be developed to sequester CO_2, it should meet the standard that USEPA ultimately adopts for CO_2 emissions, when this standard becomes applicable.

67. The application incorrectly identifies the NOx limit that will apply to proposed oxy-combustion boiler under the NSPS for Electric Utility Steam Generating Units, 40 CFR 60 Subpart Da. The application (June 2013 Submittal, page 23) indicates that this boiler will have to comply with a NOx emission limit of 0.07 lb/MWh (gross) or 0.76 lb/MWh (net), 30 day rolling average, pursuant to 40 CFR 60.44Da(f)(1). However, 40 CFR 60.44Da(f) only applies to certain integrated gasification combined cycle (IGCC) units and the oxy-combustion boiler is not an IGCC unit.

In fact, the numerical emission limits that are relevant for the new oxy-combustion boiler for NOx pursuant to the NSPS, 40 CFR 60 Subpart Da, are correctly identified in the application. However, as observed by this comment, the application incorrectly referred to 40 CFR 60.44Da(f)(1) as the regulatory basis for these limits. The application should have referred to 40 CFR 60.44Da(g)(1). This discrepancy

[64] Pursuant to Section 111(b)(1)(B) of the Clean Air Act, when USEPA proposes NSPS regulations for a category of source, it must complete adoption of such rules within one year after the date that the proposed regulations are published in the Federal Register.

[65] The history of USEPA's proposed NSPS for GHG emissions of new EGUs illustrates another reason why the provisions of the NSPS that USEPA has now proposed should not be included in the construction permit. The issuance of a proposed rule by USEPA does not mean that a rule will even be adopted pursuant to that proposal. In this regard, the current proposal is USEPA's <u>second</u> proposed rule. The previous proposal was published in the Federal Register on April 13, 2012. Concurrent with issuing its new proposal, USEPA plans to formally withdraw the earlier proposed rule. That proposal did not proceed to timely completion, in part, due to the number of public comments that were submitted on the proposal.

was addressed in the draft permit, which correctly cites 40 CFR 60.44Da(g). (See Condition 2.1.3-1(a).)

Moreover, as observed elsewhere by this commenter, the NSPS regulations are "self-executing." As such, even if this error in the application had not been identified and there were an error in the construction permit with respect to the applicable provisions of the NSPS, the oxy-combustion boiler would still be subject to the actual standards and other requirements that are applicable under the NSPS.

68. 40 CFR 60.44Da(g)(1) sets two standards that will apply to the oxy-combustion boiler for emissions of NOx. As provided below, one standard is expressed in terms of the gross energy output of the unit and the other expressed in terms of the net energy output of the unit.[66] Condition 2.1.3-1(a)(ii)(A) of the draft permit only includes the NSPS standard for NOx that is expressed in terms of gross energy output. The permit must require compliance with both standards. The permit must also include monitoring and reporting of net electricity production.

> (1) For an affected facility which commenced construction or reconstruction, any gases that contain NOx in excess of either:
>
> (i) 88 ng/J (0.70 lb/MWh) <u>gross</u> energy output; or
> (ii) 95 ng/J (0.76 lb/MWh) <u>net</u> energy output.
>
> 40 CFR 60.44Da(g)(1)[2013] (emphasis added)

This comment does not show that the proposed facility must meet both numerical limits under the NSPS for NOx. Indeed, this comment is not accompanied by any explanation or factual support for this position other than the text of the relevant provision, itself. Such support would be needed for the permit to reflect the position taken in this comment. This is because the actual wording of the relevant provision and other provisions of the NSPS indicate that these are alternative standards and a subject unit need only comply with one of them, not both. This is confirmed by a review of the adoption of this standard, including explicit statements by USEPA.

With respect to the wording of the provision, 40 CFR 60.44Da(g)(1) does not state that both limits must be met. It provides that <u>either</u> one limit <u>or</u> the other limit must be met. The use of the words "either" and "or" to link the two numerical

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[66] In its entirety, 40 CFR 60.44Da(g) [2013] provides that: "Except as provided in paragraphs (h) of this section and 40 CFR 60.45Da, on and after the date on which the initial performance test is completed or required to be completed under 60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification after May 3, 2011, shall cause to be discharged into the atmosphere from that affected facility any gases that contain NOx (expressed as NO_2) in excess of the applicable emissions limit specified in paragraphs (g)(1) through (3) of this section.

(1) For an affected facility which commenced construction or reconstruction, any gases that contain NOx in excess of either: (i) 88 ng/J (0.70 lb/MWh) gross energy output; or (ii) 95 ng/J (0.76 lb/MWh) net energy output."

limits means that a subject unit need only comply with one of the limits, not both. This is confirmed by the relevant language of 40 CFR 60.48Da(d), the related provision that addresses the procedures by which compliance with the NOx emission standard is to be shown. For subject units like the proposed oxy-combustion boiler, for which construction has not yet commenced, it provides for compliance to be shown with the applicable NOx limit with which a source has elected to comply.

> **…For affected facilities for which construction, modification, or reconstruction commenced after May 3, 2011, compliance with applicable 30-boiler operating day rolling average SO_2 and NO_X emissions limits is determined by dividing the sum of the SO_2 and NO_X emissions for the 30 successive boiler operating days by the sum of the gross energy output or net energy output, <u>as applicable</u>, for the 30 successive boiler operating days.**
>
> **40 CFR 60.48Da(d) [2013] (emphasis added)**

The fact that these limits are alternatives is also demonstrated by a review of the history of provision. When 40 CFR 60.44Da(g)(1) was proposed by USEPA, it only included a single NOx limit, expressed in terms of gross energy output. USEPA solicited comments on whether a limit in terms of net energy output should be adopted. (76 FR 24976, May 3, 2011). In the final rule, USEPA also included a NOx limit in terms of net energy output. However, USEPA did not reopen the rulemaking for comment on this second limit. (77 FR 9304, Feb. 16, 2012). Accordingly, the NOx limit in 40 CFR 60.44Da(g)(1) that is in terms of net energy cannot be a mandatory limit. It must be an additional, "alternative limit" that would potentially be appropriate for certain subject units with an effect that is identical or less stringent than the NOx limit in terms of gross energy output that underwent public comment. In fact, this is what USEPA stated in its written response to public comments concerning the adoption of limits in terms of net energy for NOx, as well as SO_2 and PM, when adopting 40 CFR 60.44Da(g).

> **Due to the lack of net output-based emission rates for multiple types of EGUs with various control configurations over a range of operating conditions, the final rule allows, but does not require, the use of a net-output based standard as an alternative to the gross-output based standard.**
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> **USEPA, OAQPS, Response to Public Comments on Rule Amendment Proposed May 3, 2011, December 2011,[67] p 4.**

[67] ***Standards of Performance for Fossil Fuel-Fired Steam Generating Units for Which Construction Is Commenced after August 17, 1971 (40 CFR 60, Subpart D), Standards of Performance for Electric Utility Steam Generating Units for Which Construction Is Commenced after September 18, 1978 (40 CFR 60 Subpart Da), et al., Response to Public Comments on Rule Amendments Proposed May 3, 2011*** **(73 FR 33642), USEPA, December 2011.**

Accordingly, the permit properly addresses only the limit for NOx in terms of gross energy output, which is the limit with which the source indicates it will comply. As such, it is not necessary for the permit to require monitoring and recordkeeping for net energy output.[68]

69. Similarly, for the alternative standards of the NSPS for combined emissions of NOx and CO, Condition 2.1.3-1(a)(ii)(B) must include both the gross and net energy output standards in 40 CFR 60.45Da(b)(1)[69] and clearly provide that the oxy-combustion generating units has to comply with both standards.

For the reasons already discussed above, this comment does not demonstrate that the NSPS limits for combined NOx and CO expressed in terms of gross energy output and net energy output must both be met.[70] As such, the permit properly addresses only the limit in terms of gross energy output, which is the limit with which the source indicates it will comply.

70. Similarly, 40 CFR 60.44Da(g)(1)[71] sets three standards that will apply to the oxy-combustion boiler for its SO_2 emissions, one standard expressed in terms of its gross energy output, one expressed in terms of its net energy output, and one in terms of the reduction in SO_2 emissions provided by the SO_2 emission control system. Condition 2.1.3-1(a)(i) of the draft permit only includes the NSPS standard for SO_2 that is expressed

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[68] As the oxy-combustion boiler would be complying with the NSPS limit for NOx emissions in terms of gross energy output, the source will have to fulfill relevant monitoring and recordkeeping requirements of NSPS related to gross energy output.

[69] 40 CFR 60.45Da(b) (1) [2013] provides that: "On and after the date on which the initial performance test is completed or required to be completed under 40 CFR 60.8 no owner or operator of an affected facility that commenced construction, reconstruction, or modification after May 3, 2011, shall cause to be discharged into the atmosphere from that affected facility any gases that contain NOx (expressed as NO_2) plus CO in excess of the applicable emissions limit specified in paragraphs (b)(1) through (3) of this section as determined on a 30-boiler operating day rolling average basis.

(1) For an affected facility which commenced construction or reconstruction, any gases that contain NOx plus CO in excess of either: (i) 140 ng/J (1.1 lb/MWh) gross energy output; or (ii) 150 ng/J (1.2 lb/MWh) net energy output."

[70] As related to the compliance provisions of the NSPS for the standards for combined emissions of NOx and CO, 40 CFR 60.48Da(g) provides: "For affected facilities for which construction, modification, or reconstruction commenced after May 3, 2011, compliance with applicable 30-boiler operating day rolling average NO_X plus CO emissions limit is determined by dividing the sum of the NO_X plus CO emissions for the 30 successive boiler operating days by the sum of the gross energy output or net energy output, <u>as applicable</u>, for the 30 successive boiler operating days." [emphasis added]

[71] 40 CFR 60.43Da(g) provides that: "Except as provided in paragraphs (h) of this section and 40 CFR 60.45Da, on and after the date on which the initial performance test is completed or required to be completed under 60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification after May 3, 2011, shall cause to be discharged into the atmosphere from that affected facility any gases that contain NOx (expressed as NO_2) in excess of the applicable emissions limit specified in paragraphs (g)(1) through (3) of this section.

(1) For an affected facility which commenced construction or reconstruction, any gases that contain NOx in excess of either: (i) 88 ng/J (0.70 lb/MWh) gross energy output; or (ii) 95 ng/J (0.76 lb/MWh) net energy output." 40 CFR 60.44Da(g)(1)[2013].

in terms of gross energy output. The permit must require the oxy-combustion generating unit to comply with all three standards for SO_2.

For the reasons already discussed, this comment does not demonstrate that all three NSPS limits for SO_2 must be met.[72] In this regard, since the limits in terms of gross energy output and net energy output are alternative limits, the third limit, which is expressed in terms of the reduction in SO_2 emissions, must also be an alternative limit. Accordingly, the permit properly addresses only the two limits with which the source indicates that it will comply, the limits in terms of gross energy output or, in the alternative, the limit for reduction in SO_2 emissions.

71. Similarly, for the standard of the NSPS for PM, Condition 2.1.3-1(a)(iii) must include both the gross and net energy output standards in 40 CFR 60.45Da(b)(1)[73] and clearly provide that the oxy-combustion generating units has to comply with both standards.

For the reasons already discussed, this comment does not demonstrate that both NSPS limits for PM must be met.[74] As such, the permit properly addresses only the PM limit in terms of gross energy output, which is the limit with which the source indicates it will comply.

72. 40 CFR 60.48Da(a) provides that: "For affected facilities for which construction, modification, or reconstruction commenced after May 3, 2011, the applicable SO_2 emissions limit under 40 CFR 60.43Da, NOx emissions limit under 40 CFR 60.44Da, and NOx plus CO emissions limit under 40 CFR 60.45Da apply at all times." For the oxy-combustion boiler, the construction permit should make clear that these limits apply

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[72] **As related to the compliance provisions of the NSPS for the standards for SO_2 emissions, 40 CFR 60.48Da(d) provides: "For affected facilities for which construction, modification, or reconstruction commenced after May 3, 2011, compliance with applicable 30-boiler operating day rolling average SO_2 and NOx emissions limits is determined by dividing the sum of the SO_2 and NOx emissions for the 30 successive boiler operating days by the sum of the gross energy output or net energy output, <u>as applicable</u>, for the 30 successive boiler operating days." [emphasis added]**

[73] 40 CFR 60.45Da(b)(1) (e) provides that: "Except as provided in paragraph (f) of this section, the owner or operator of an affected facility that commenced construction, reconstruction, or modification commenced after May 3, 2011, shall meet the requirements specified in paragraphs (e)(1) and (2) of this section.

(1) On and after the date on which the initial performance test is completed or required to be completed under 40 CFR 60.8, whichever date comes first, the owner or operator shall not cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of the applicable emissions limit specified in paragraphs (e)(1)(i) or (ii) of this section.

(i) For an affected facility which commenced construction or reconstruction: (A) 11 ng/J (0.090 lb/MWh) gross energy output; or (B) 12 ng/J (0.097 lb/MWh) net energy output."

[74] **As related to the compliance provisions of the NSPS for the standards for SO_2 emissions, 40 CFR 60.48Da(n) provides:**

"Compliance provisions for sources subject to §60.42Da(c)(1) or (e)(1)(i). The owner or operator shall calculate PM emissions by multiplying the average hourly PM output concentration (measured according to the provisions of §60.49Da(t)), by the average hourly flow rate (measured according to the provisions of §60.49Da(l) or §60.49Da(m)), and dividing by the average hourly gross energy output (measured according to the provisions of §60.49Da(k)) or the average hourly net energy output, <u>as applicable</u>." [emphasis added]

during startup, shutdown and malfunction. The permit should also ensure that the permit has monitoring and reporting to ensure compliance at all times.

In response to the request made in this comment, the issued permit incorporates the language of 40 CFR 60.48Da(a). (See revised Condition 2.1.3-1.) This is not unreasonable as 40 CFR 60.48Da(a) directly addresses the applicability of the emission limits in 40 CFR 60 Subpart Da that apply to the oxy-combustion boiler. It also may avoid future misunderstanding about the applicability of these limits.

Accordingly, for the oxy-combustion boiler, the issued permit indicates that the standards of the NSPS for SO_2, NOx and NOx plus CO apply at all times, consistent with the language of 40 CFR 60.48Da specifically cited by this comment. In addition, although not cited by this comment, the issued permit also indicates that the NSPS limits for PM and opacity do not apply during startup and shutdown, as also provided by 40 CFR 60.48Da(a).

73. The Illinois EPA must make a determination of whether this facility, with its large parasitic energy loads from the ASU, CPU and two scrubbers, can comply with emission standards under the NSPS that are expressed in terms of net energy output. If the facility cannot, the Illinois EPA must deny the permit.

As already discussed, this commenter has not demonstrated that the proposed facility must comply with both the limits of the NSPS that are expressed in terms of the net energy output and the standards that are expressed in terms of gross energy output. As such, it is sufficient for the application to show compliance with the NSPS limits in terms of gross energy output, which it does.

Moreover, it is reasonable for the source to comply with the limits in terms of gross energy output. This is because USEPA did not consider oxy-combustion facilities with sequestration when it set limits in terms of net energy output under the NSPS.

74. The NSPS regulations are self-executing. In this regard, this minor source permit cannot shield the source from the obligation to comply with applicable requirements of the NSPS. Even if Illinois EPA does not correct the errors in the draft permit with respect to the NSPS that I have identified in my comments, I can and will enforce the net energy emission limits of the NSPS if they are violated.

The Illinois EPA agrees that the NSPS regulations are “self-executing.” That is, the effectiveness of the NSPS regulations is independent of the issuance of a construction permit that identifies or specifies the requirements of the NSPS that are applicable to particular new, modified or reconstructed emission units. As already discussed, this commenter has not demonstrated that there are errors in the approach that has been taken in the permit for the oxy-combustion boiler with respect to the NSPS.

75. Draft Condition 2.1.9-6 requires emission monitoring for CO_2. However, it refers to 40 CFR 60.49Da(a),[75] which addresses continuous opacity monitoring systems (COMS) and other opacity measuring techniques. Thus, it appears the draft permit did not mean to cite to 40 CFR 60.49Da(a). I cannot tell what Illinois EPA meant to cite to. Therefore, I should be given an opportunity to comment on this issue after Illinois EPA addresses it.

The error identified in this comment has been corrected in the issued permit, i.e., Condition 2.1.9-6 no longer refers to 40 CFR 60.49Da(a). In fact, the reference to 40 CFR 60.49Da(a) in the draft permit was superfluous. The remainder of the condition, as present in the draft permit, clearly identified the nature of the continuous emissions monitoring that would be required for the oxy-combustion boiler for CO_2 emissions. In this regard, the condition provided that such monitoring would be required to be conducted in accordance with 40 CFR 75.10(a)(3), provisions of the federal Acid Rain Program that address monitoring of CO_2 emissions.

The fact that the Illinois EPA has responded to this comment by a change in the issued permit does not mean that the commenter is entitled to a further opportunity to comment. In this respect, this comment is similar to other comments in which changes have been made between the draft permit and the issued permit in response to comments.

76. The construction permit must make clear that 40 CFR 60.49Da(f)(2) is not applicable to monitoring to comply with the CO_2 and all other annual emission limits in Condition 2.1.6(b) of the permit. 40 CFR 60.49Da(f)(2) allows sources to ignore their emissions 10 percent of the time during boiler operating days and all of the time when a day is not a boiler operating day. This means that monitoring for a limit that is supposed to refer potential to emit and keep the source from triggering PSD would substantially underreport actual emissions. This would make the permit not enforceable as a practical matter. Therefore, the permit must require monitoring for CO_2, SO_2 and NOx at all times that the boiler is combusting any fuel. This may require redundant CEMS.

This comment does not support the change to the permit that is requested. First, 40 CFR 60.49Da(f)(2) is not applicable to continuous monitoring for CO_2. As a purely factual matter, this is because 40 CFR 60 Subpart Da does not set emission limits for CO_2 and, accordingly, does not address monitoring of CO_2 emissions.[76] In addition, 40 CFR 60.49Da(f)(2) does not allow sources "to ignore their emissions" at certain times. For NOx and SO_2, for which 40 CFR 60 Subpart Da does require continuous monitoring, 40 CFR 60.49Da(f)(2) sets <u>minimum</u>, <u>quantitative</u> requirements for data collection by these monitoring systems. If these minimum requirements cannot be met by a monitoring system installed on a subject unit, 40 CFR 60.49Da(f)(2)

[75] Draft Condition 2.1.9-6 states "Pursuant to 40 CFR 60.49Da(a) for the affected boiler, the Permittee shall install, certify, operate and maintain a CEMS for CO_2 emissions."

[76] USEPA is engaged in rulemaking to adopt an NSPS, 40 CFR 60 Subpart TTTT, that would set standards for CO_2 for new electrical generating units.

requires that a source take necessary actions to meet these minimum requirements, which potentially could include installation and operation of a redundant monitoring system.[77] The establishment by 40 CFR 60.49Da(f)(2) of a minimum quantitative requirement for data collection does not condone or legitimize poor operation of a continuous monitoring system by a source simply because this minimum requirement is met. As already explained, other requirements apply to the operation of continuous emission monitoring systems that address aspects of proper operation of such systems other than the percentage of data that is collected.

As a more general matter, this comment implies that the source need not account for emissions of the oxy-combustion boiler during any periods when continuous emission monitoring systems are not operated. This is not the case. The source must account for all emissions when determining compliance with the emission limits that have been set by the permit. For the oxy-combustion boiler for pollutants for which continuous emissions monitoring is conducted, during any periods when emission data is not available from the monitoring system, the source must determine emissions using "credible data," consistent with USEPA's principle of credible evidence. In most cases, it is expected that this will simply require use of emission data collected by the monitoring system for another period of time in which the operation of the boiler was similar to that during the period in which the data was not available from the monitoring system.[78]

77. Condition 2.1.3-1(b)(i)(C) in the draft permit would set a mercury limit of 0.003 lb/GWh for "not low rank coal" and 0.04 lb/GWh for "low rank coal." In order for this condition to be enforceable as a practical matter, it must define low rank coal. In addition, this condition must explain what the emission limit is when a facility burns a blend of low rank and not low rank coal. This is important because FutureGen intends to burn a blend of Wyoming coal and Illinois coal.

Upon further consideration in response to this comment, Condition 2.1.3-1(b)(i)(C) in the issued permit only includes the more stringent limit for mercury in the NESHAP, 40 CFR 63 Subpart UUUUU, for "coal that is not low rank coal" (i.e., the

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[77] In fact, for units constructed after February 28, 2005, a "boiler operating day" is defined by 40 CFR 60.41Da to mean "a 24-hour period between 12 midnight and the following midnight during which any fuel is combusted at any time in the steam-generating unit. It is not necessary for fuel to be combusted the entire 24-hour period." As such, the minimum data collection requirement set by 40 CFR 60.49Da(f)(2) for the monitoring systems on the oxy-combustion boiler that are required by the NSPS is collection of emission data for at least 90 percent of all operating hours for each 30 successive boiler operating days.

This requirement is different than the minimum data collection requirement for older units set by 40 CFR 60.49Da(f)(1), for which a different definition of "boiler operating day" applies. For older units subject to 40 CFR 60 Subpart Da, a boiler operating day means "a 24-hour period during which fossil fuel is combusted in a steam generating unit for the entire 24-hour period."

[78] In circumstances in which representative monitoring data is not available, the source will need to conduct an engineering analysis to develop credible emission data for the boiler. It is expected that this would involve interpolation or extrapolation from the best, available data collected by the monitoring system, to account for the actual operation of the boiler during the period when data from the monitoring system was not available.

limit for a unit that is not a "unit designed for low rank virgin coal"). The condition does not include the alternative, less stringent limit for "low rank coal" (i.e., the limit for a "unit designed for low rank virgin coal"). Under the NESHAP, one criterion for a "unit designed for low rank virgin coal" is that it be "… at or near the mine that produces such coal." This will never be the case for the oxy-combustion boiler. The heat content of Illinois coal, which is the only coal that could potentially ever be mined near the facility, is above the level necessary for it to be considered low rank coal. As such, the oxy-combustion boiler will never qualify as a "unit designed for low rank virgin coal."[79]

78. Condition 2.6.4 does not have a $PM_{2.5}$ limit. However, the application (June 2013 submittal, Attachment No. 8) claims maximum emissions of 0.11 tpy. I dispute that this is what the emissions will be. However, to the extent Illinois EPA maintains that this is what emissions will be, the permit must contain this limit and include testing, monitoring and reporting to ensure this limit is not violated. Condition 2.6.4 needs testing, monitoring and reporting to ensure this limit is not violated.

This comment does not show that the permit should limit the $PM_{2.5}$ emissions of roadways to 0.11 tpy. First, 0.11 tpy is the potential $PM_{2.5}$ emissions from roadways that the Applicant <u>initially</u> provided. As already discussed, the Applicant initially used a value of 0.6 g/m^2 for silt loading in its emission calculations for roadways. The Applicant subsequently submitted revised emission data that was calculated using a value of 2.0 g/m^2. The emission limits for roadways in the permit reflect this later data. Second, in preparing the permit, the Illinois EPA decided to set a single limit for emissions of PM_{10} and $PM_{2.5}$ from roadways, 1.9 tpy, based on the revised emission data provided by the Applicant for PM_{10}. A single limit for $PM_{10}/PM_{2.5}$ will simplify review of the compliance determinations that are made by the source for roadways. A separate, lower emission limit for the $PM_{2.5}$ emissions from roadways is not needed for the net increase in emissions of $PM_{2.5}$ from the proposed project to be less than significant. A separate limit for $PM_{2.5}$ emissions also would not meaningfully affect the net change in emissions of $PM_{2.5}$ from this project.

[79] It was not necessary for the draft permit to supply a definition of the term "low-rank coal." The classification of coal for purposes of the mercury standard in the NESHAP, 40 CFR 63 Subpart UUUUU, is governed by the definitions for "Unit designed for coal ≥ 8,300 Btu/lb subcategory" and "Unit designed for low rank virgin coal subcategory," at 40 CFR 63.10042, as follow (emphasis added):

> ***Unit designed for coal ≥ 8,300 Btu/lb subcategory*** **means any coal-fired EGU that is not a coal-fired EGU in the "unit designed for low rank virgin coal" subcategory.**
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> ***Unit designed for low rank virgin coal subcategory*** **means any coal-fired EGU that is designed to burn and that is burning non-agglomerating virgin coal having a calorific value (moist, mineral matter-free basis) of less than 19,305 kJ/kg (8,300 Btu/lb) that is constructed and operates <u>at or near the mine that produces such coal</u>.**

As already discussed, the issued permit includes appropriate provisions for verification of compliance with the emission limits that have been set for roadways. In particular, in response to another comment, the issued permit requires measurements for the silt loading on roadways (new Condition 2.6.5-2). If an operating program for roadways that involves more than normal housekeeping practices for roadways must be implemented to ensure compliance with applicable limits, such an operating program is required to be implemented (Condition 2.6.3(b)). Recordkeeping for the implementation of this program is also required (Condition 2.6.6(b)).

79. The Illinois EPA should define what is meant by "design PM and PM_{10} emission rates" in Draft Permit Condition 2.6.6(a)(ii).

Condition 2.6.6(a)(ii) serves to enhance the practical enforceability of the emission limits for roadways. This is because it requires the source to keep projections for the maximum emissions from roadways. This acts to require the source to appropriately plan and undertake measures to ensure that actual emissions comply with the applicable emission limits. In this regard, this condition also provides the mechanism by which it will be determined if an operating program must be implemented for roadways or whether normal housekeeping practices will be sufficient to determine compliance with the emission limits that have been set for roadways. In response to comments, in the issued permit, this condition has been enhanced to make its purposes clear.

80. Condition 2.6.6(c) is not sufficient as it does not require testing or monitoring.

As already discussed, the issued permit includes appropriate provisions for verification of compliance with the emission limits that have been set for roadways. These provisions are set forth elsewhere in the permit than in Condition 2.6.6(c). Condition 2.6.6(c) requires specific recordkeeping for the particulate emissions of roadways, based on the information and data collected pursuant to these other provisions of the permit, to directly confirm compliance with the emission limits that have been set for roadways in Condition 2.6.4.

81. FutureGen would be an oxy-combustion power plant designed to enable the use of carbon capture and sequestration (CCS) to control up to 90 percent of the facility's CO_2 emissions. It would be one of the very first utility-scale electric generating CCS projects in the country. I have supported the FutureGen project over the years, conditioned upon its promise of demonstration of CCS technology in which nearly all CO_2 is captured and sequestered.

However, that promise of CCS demonstration would not be required by the draft permit, which would not require the capture or sequestration of any CO_2. Instead, Condition 2.1.6(b) of the draft permit would allow the facility to emit over 1.4 million tons of CO_2 annually. This level of emissions reflects "continuous operation of the oxy-combustion boiler at the maximum emission rate under the mode of operation with the greatest emissions." (Project Summary at 3-4). In other words, the Draft Permit would allow operation of FutureGen as a conventional coal-fired plant, without deploying CCS. The Draft Permit would authorize the construction and operation of a different facility than what FutureGen, as originally proposed, was intended to achieve, and a different plant than what I have supported. The Illinois EPA should repropose a permit that reflects the model CCS project that FutureGen is supposed to be.

This comment does not provide a legal basis for the action that is requested, i.e., inclusion of specific performance requirements related to CCS in the construction permit for the facility. In particular, the comment does not show that such provisions are necessary to ensure that the proposed facility is not a major project for GHG emissions under the PSD program.

Moreover, as acknowledged by this comment, this facility will be a demonstration project. Not only will it be one of the very first utility-scale CCS projects in the country, it will also be a full-scale demonstration project for oxy-combustion technology. As such, it is not unreasonable for the Applicant to have submitted a permit application that does not require that the construction permit establish specific performance requirements for CCS. This avoids requirements for performance of CCS by the facility that may not be able to be achieved, at least initially, as the facility would be a demonstration facility and use technology that has not been demonstrated at the scale of the proposed facility. At the same time, the facility will be subject to requirements related to CCS that are imposed by the USDOE. These requirements will consider both the goals for this project and the circumstances that are present for this facility as it is a demonstration project. The facility will likely be subject to requirements related to CCS that are eventually established by USEPA in its new NSPS for GHG emissions of new electricity utility generating units. The facility may also become subject to requirements related to CCS as a consequence of actions and agreements that take place in the context of the Illinois Power Agency Act.

82. This permit must include emission limits based on Best Available Control Technology (BACT) determinations for the pollutants, including CO_2 and other GHG, for which the new plant would cause net emissions increases.

As already discussed elsewhere in this document, this project does not result in a significant net emissions increase for any PSD regulated pollutants and consequently is not subject to the BACT requirement of the PSD rules.

83. One central PSD requirement is the inclusion of BACT limits for each regulated pollutant for which a major modification would create a significant net emissions increase at the source. 42 U.S.C. § 7475(a)(4)[80]. The Clean Air Act defines BACT as:

> an emission limitation based on the maximum degree of reduction of each pollutant subject to regulation under this chapter emitted from or which results from any major emitting facility, which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility through application of production processes and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques for control of each such pollutant.
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> 42 U.S.C. § 7479(3).

While the observation made in this comment is correct, it is not relevant to the permitting of the proposed project. As already discussed, the proposed project is not a major project under the PSD rules. The increase or net increase in emissions of all regulated PSD pollutants from this project will not be significant, in part due to the contemporaneous decreases in emissions from the permanent shutdown of the existing boilers at the Meredosia Energy Center. As such, the project is not subject to the BACT requirement of the PSD rules.

84. The Illinois EPA has acknowledged that the new oxy-combustion boiler and most of the other changes occurring because of the FutureGen 2.0 project are new construction and/or physical changes or changes of operation. Furthermore, Illinois EPA has acknowledged that these activities will create significant emissions increases for regulated pollutants. Illinois EPA states:

> For many . . . pollutants, . . . the increases in emissions with the proposed plant exceed the significant emission thresholds for a major project under the PSD rules.
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> Project Summary, pp 3-5 (identifying significant emissions increases of particulate matter, PM_{10}, $PM_{2.5}$, SO_2, NOx, CO, sulfuric acid mist, and GHG).

The only issue with regard to PSD applicability is whether the changes cause significant net emissions increases. Illinois EPA claims that they do not. *See e.g.* Draft Permit at Finding 3 ("this project will not be accompanied by significant net increases in emissions of PSD pollutants"). Illinois EPA's analysis of net emissions increases is flawed, though, and PSD is an applicable requirement for these pollutants which requires the Applicant to obtain a PSD permit, including BACT limits.

[80] "No major emitting facility . . . may be constructed in any area . . . unless . . . (4) the proposed facility is subject to the best available control technology for each pollutant subject to regulation under this chapter emitted from, or which results from, such facility." 42 U.S.C. § 7475(a)(4).

Using an appropriate baseline would significantly reduce the emissions decreases that the Illinois EPA has credited to the shutdown of Boilers 1 through 6. For example, for the calendar years 2009 to 2011, the average annual CO_2 emissions at the Meredosia Energy Center were 865,650 tons—far less than both the CO_2e baseline of 1,937,858 tpy for the Meredosia Energy Center and FutureGen's the CO_2e emissions of 1,522,503 tpy.[81] Using an appropriate baseline would trigger PSD requirements, including BACT, at a minimum, for GHG, $PM_{2.5}$ and NOx.

In its Project Summary, Illinois EPA fails to explain why it accepted a baseline period of March 2007 through February 2009, other than to state that this is was a period during which "all these boilers operated." (Project Summary, p. 5 n.8.) This explanation contradicts the plain language of 40 CFR 52.21(b)(48)(i), which limits the baseline period to one during the "5-year period immediately preceding when the owner or operator begins actual construction of the project." In any case, the explanation's applicability to the Meredosia Energy Center is entirely unclear. Illinois EPA's implication might be that using the selected baseline period would more accurately reflect emissions from each of the boilers, because it would correct for any increased utilization of Boilers 5 and 6 following the retirement of Boilers 1 through 4. That would not be the case for the Meredosia Energy Center, though. For the period of 2007 to 2011, CO_2 emissions from Boilers 5 and 6 peaked in 2007.[82] CO_2 emissions from Boilers 5 and 6 declined even after the retirement of Boilers 1 through 4, likely because of reduced market demand. In accordance with the plain language of 40 CFR 52.21(b)(48)(i), Illinois EPA must use a later baseline period for Boilers 1 through 6, starting no later than August 2009, that reflects the reduced market demand for the now-shuttered Meredosia Energy Center. Using an appropriate period triggers PSD requirements for FutureGen, including BACT.

As already discussed, a proper netting analysis was performed using an appropriate baseline period for the contemporaneous decreases in emissions from the shutdown of the existing boilers. The Illinois EPA did not select the baseline period because it would correct for any increased utilization of Boilers 5 and 6 following the retirement of Boilers 1 through 4, as suggested by this comment. The Applicant selected the baseline periods for the contemporaneous emissions decreases from the shutdowns of the existing boilers in accordance with the provisions for baseline periods under 40 CFR 52.21(b)(48)(i). As allowed for by this rule, the Applicant elected to use the same baseline period for the shutdown of Boilers 1 through 4 and the shutdown of Boilers 5 and 6, March 2007 through February 2009.   In fact, pursuant to 40 FR 52.21(b)(48), the Applicant could have selected different baseline periods for the shutdown of each group of boilers as each of these shutdowns was a separate project. The Applicant also could have selected different baseline periods

[81] Annual emission rates for Meredosia Boilers 1 through 6 are available from the USEPA' Air Markets Program Data, available at http://ampd.epa.gov/ampd/QueryToolie.html. The Meredosia plant's CO_2 emissions for 2009, 2010, and 2011 were 640,404 tons; 914,512 tons; and 1,042,004 tons, respectively.
[82] In 2007, Boilers 5 and 6 emitted 1,544,108 tons of CO_2, significantly higher than its CO_2 emissions during 2009 through 2011.

for different pollutants. Such changes to the selected baseline periods would potentially have resulted in greater emissions decreases.[83]

85. The BACT analysis that is required for GHG emissions must take into account USEPA's proposed *Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units* ("GHG NSPS Prepublication Version of Proposal") (Sept. 20, 2013).[84] *See In re St. Lawrence Cty. Solid Waste Disposal Auth.*, PSD 90-9 (EAB 1990) (remanding PSD permit for permitting authority to consider USEPA determinations in proposed NSPS). In its proposal, USEPA makes clear its determination that implementation of CCS is achievable for new coal-fired boilers. *See, e.g.*, GHG NSPS at PDF pp. 25-26. The Illinois EPA's GHG BACT analysis for FutureGen therefore must reflect both USEPA's determination, as well as the reality that FutureGen's central purpose is to serve as a demonstration of CCS technology to control up to 90 percent of the facility's CO_2 emissions.

As already discussed, the GHG emissions of the proposed project are not subject to the substantive requirements of PSD, including BACT. This is because the net increase in GHG emissions is below the significant emission rate for GHG. However, the proposed facility will likely be subject to future requirements for CO_2 emissions under USEPA's NSPS for EGUs, 40 CFR 60 Subpart TTTT. Given the facility's use of CCS, it is anticipated that the CO_2 emissions from the oxy-combustion boiler will meet the applicable requirements.

The circumstances of the proposed project are not the same as those addressed by the Environmental Appeals Board (EAB) in *In re St. Lawrence* (*In re St. Lawrence County Solid Waste Auth.*, PSD Appeal No. 90-9, slip op. at 1-3 (Adm'r July 27, 1990)). In *St. Lawrence*, the EAB heard an appeal of a PSD permit for a project that was subject to BACT.[85] **As the FutureGen project does not require a PSD permit for GHG emissions, this comment's reliance on *In re St. Lawrence* is unavailing.**

[83] **40 CFR 52.21(b)(48) does not require that a single baseline period be used in a netting analysis for all emission units and all pollutants covered by the analysis. 40 CFR 52.21(b)(48)(i)(*c*) only provides that "For a regulated NSR pollutant, when a project involves multiple emission units, only one consecutive 24-month period must be used to determine the baseline actual emissions for the units being changed. A different consecutive 24-month period can be used For (sic) each regulated NSR pollutant."**

[84] *Available at* http://www2.epa.gov/sites/production/files/2013-09/documents/20130920proposal.pdf.

[85] **In *St. Lawrence*, the EAB heard an appeal of a PSD permit for a resource recovery facility in which the BACT limits set for NOx, SO_2 and CO were challenged. The basis of this appeal was that in the BACT analysis, the permitting authority had not considered USEPA's proposed NSPS rules for municipal waste incinerators, which addressed emissions of NOx, SO_2 and CO. The EAB found that the proposal of limits for these pollutants by USEPA in this rulemaking represented a determination by USEPA that the proposed limits were "presumptively achievable using currently available technologies." As such, the limits proposed by USEPA had to be considered in the BACT analysis, where they "should serve as the starting point" for BACT determinations.**

FOR ADDITIONAL INFORMATION

Questions about the public comment period and the permit decisions should be directed to:

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LISTING OF SIGNIFICANT CHANGES BETWEEN THE DRAFT AND ISSUED PERMITS

<u>Changes to the Permit for the Oxy-Combustion Power Plant, Permit No. 12020013</u>

<u>Section 1: Source-Wide Conditions</u>

Condition 1.2(a) – In response to a comment concerning the timing of the contemporaneous emission decreases for this proposed project, an additional provision has been included in the issued permit that provides that the permit will expire if construction is not commenced by August 31, 2014. This provision will explicitly address the timing of the contemporaneous emission decreases from existing Boilers 1 through 4, terminating the authorization to construct provided by the permit at the point when these decreases would cease to be contemporaneous.

Condition 1.2(c) – In response to a comment, the issued permit limits the emissions of sulfuric acid mist from the existing emergency diesel fired engine generator at the source. This change ensures that any increases in emissions of sulfuric acid mist from this contemporaneous construction project are no more than 0.008 tons per year. In addition, this condition includes compliance provisions to verify compliance with this limit for sulfuric acid mist emissions from this engine, including relevant records for the operation of this engine, the methodology by which emissions of sulfuric acid mist are determined, and the emissions of sulfuric acid mist.

<u>Section 2.1: Unit-Specific Conditions for the Oxy-Combustion Boiler</u>

Condition 2.1.3-1(a) – In response to a comment, the issued permit incorporates the language of 40 CFR 60.48Da(a) of the NSPS for Electric Utility Steam Generating Units. The additional language provides that the standards of this NSPS for SO_2 and NOx or NOx plus CO apply at all times. As a consequence of the further review of 40 CFR 60.48Da that was prompted by the comment, the issued permit also includes other relevant language of this provision, which provides that the limits of this NSPS for PM and opacity apply at all times except during periods of startup and shutdown.

Condition 2.1.3-1(b)(i)(C) – In response to a comment, the issued permit only includes the more stringent limit for mercury in the NESHAP, 40 CFR 60 Subpart UUUUU, for a unit firing "coal that is not low rank coal," 0.003 lb/GWh. The less stringent mercury limit for a unit firing "low rank coal" is not included. This is because this other limit would never be applicable to this boiler.

Condition 2.1.5(c) – In response to a comment expressing concern over the absence of a limit on the load of the oxy-combustion boiler when air firing, the issued permit limits the operation of this boiler to no more than the maximum load established during emissions testing for air-firing or oxy-combustion, as applicable, that demonstrates compliance with the hourly emission limits set for sulfuric acid mist and fluorides in Condition 2.1.6(b). This operational requirement will enhance the practical enforceability of the hourly limits on the emissions of sulfuric acid mist and fluorides of this boiler.

Condition 2.1.6(a)(i) – In response to a comment, the issued permit now limits the annual heat input to the oxy-combustion boiler from fuel to not more than 14.1million mmBtu/year rather 14.5 million mmBtu/year, as would have been provided by the draft permit. The comment indicated that the potential emissions of the oxy-combustion boiler were under predicted due to the erroneous use of a maximum annual heat input to the boiler that was equivalent to an hourly heat input of 1,655 mmBtu/hour, rather than the nominal heat input of capacity of the boiler, 1,605 mmBtu/hour, as indicated in the application. The limit for annual heat input in the issued permit, 14.1million mmBtu/year, is equivalent to an hourly heat input capacity of 1,605 mmBtu/hour. This change acts to maintain consistency between the limit on the heat input to this boiler set by the permit and the representation of the nominal heat input to this boiler made in the application.

Condition 2.1.6(a)(ii) – In response to a comment, the issued permit limits the amount of coal used by the oxy-combustion boiler to no more than 744,600 tons per year. The comment observed that the emission calculations in the application for the new and modified coal handling operations were based on the assumption that the amount of coal used by this boiler is no more than 744,600 tons per year. This change will make this element in the calculations for these coal handling operations enforceable and enhance the practical enforceability of the emission limits that have been set for these operations.

Condition 2.1.6(a)(iii) – In response to various comments, the issued permit limits the operation of the oxy-combustion boiler in air-firing mode (i.e., operation in other than oxy-combustion mode) to no more than 4,800 hours/year. This change will make an element in the emission calculations for the oxy-combustion boiler enforceable and enhance the practical enforceability of the emission limits that have been set for various pollutants, notably sulfuric acid mist and fluorides.

Condition 2.1.6(b) – In the issued permit, the annual limits for emissions of the oxy-combustion boiler (limits for SO_2, PM, PM_{10}/$PM_{2.5}$, VOM, CO and fluorides) are lower than the limits in the draft permit. This reflects adjustments to these limits that result from limiting the operation of this boiler in air-firing mode to no more than 4,800 hours/year, in response to comments, as discussed above.

In addition, the limit for emissions of an individual HAP is 4.5 tons per year (tpy), rather than 2.8 tpy. This corrects an error in the draft permit. The correct limit for individual HAPs was reflected in Table 1A of the draft permit.

Condition 2.1.7(c)(i) –In response to a comment, emission testing is required for the oxy-combustion boiler for sulfuric acid mist and fluorides. This testing will serve to verify compliance with the hourly emission limits that are set for these pollutants. Testing for these pollutants has been found to be reasonable because permitted emissions of these pollutants are more than half of the applicable PSD significant emission rates.

In response to another comment, the issued permit also requires emissions testing for VOM. Given test data is not available for a coal-fired utility boiler with oxy-combustion technology, it is not unreasonable for initial testing for VOM emissions to be required by the permit.

The issued permit now requires emission testing for filterable PM in addition to filterable PM_{10} and $PM_{2.5}$.and condensable particulate. This corrects an oversight in the draft permit.

Condition 2.1.7(c)(ii)(A) – The issued permit now explicitly requires that the initial emission testing for the oxy-combustion boiler include testing for both operation in air-firing mode and operation in oxy-combustion mode while operating at maximum rates. This clarification was made in response to a comment. It will avoid potential future misunderstandings about the scope of the emission testing that is required under Condition 2.1.7(c).

Condition 2.1.7(c)(ii) – A note has been added to make clear that the additional testing that must be performed for the oxy-combustion boiler pursuant to a request from the Illinois EPA may extend to pollutants for which testing was not initially required, notably for lead. This change was made in response to a comment that believed that the initial emission testing should include testing for lead. Such testing is not warranted initially because emissions of lead are regulated by a NESHAP, 40 CFR 63 Subpart UUUUU, and emissions should be well below applicable emission limits that are set by the permit. However, this provision addresses the possibility that information may arise that indicates that emission testing of this boiler is warranted for lead. It also provides for further testing for other pollutants, including sulfuric acid mist, fluorides and VOM, in the event that the initial testing for these pollutants indicates that further testing is warranted during the period before a CAAPP permit is issued that addresses this new facility.

Condition 2.1.7(c)(iii) – Test methods and procedures are now specified for testing emissions of filterable PM, VOM, sulfuric acid mist, and fluoride, as testing for these pollutants is now required.

Condition 2.1.7(c)(v) – The issued permit requires additional information in the report for emission testing related to the operating conditions of the oxy-combustion boiler during testing including the boiler's firing rate and load during testing. Information is now required detailing the maximum loads for air-firing and oxy-combustion at which the Permittee considers compliance with applicable emission limits has been demonstrated. This information is needed to implement the operational limit for the load at which the boiler is operated (new Condition 2.1.5(c)), which will be based on information for the operation of the boiler during emissions testing for sulfuric acid mist and fluorides.

Condition 2.1.9-6 – In response to an error identified by a comment, this condition no longer refers to 40 CFR 60.49Da(a). The remainder of the condition is unchanged as it clearly identifies the nature of the continuous emissions monitoring that is being required for the oxy-combustion boiler for CO_2 emissions.

Condition 2.1.10(b)(i) – Recordkeeping requirements related to operation of the oxy-combustion boiler have been enhanced in the issued permit. The additional records are needed to verify compliance with the operational limits for the amount of coal combusted in the boiler and the amount of time that the boiler operates in air-firing mode in new Conditions 2.1.6 (a)(ii) and (iii).

Condition 2.1.10(b)(iii) – Hourly recordkeeping is required for the mode of operation of the boiler and the load of the boiler as this information is needed verify compliance with the operational requirements for the amount of time that the boiler operates in air-firing mode and the load at which the boiler is operated, in new Conditions 2.1.6(a)(iii) and 2.1.5(c), respectively.

Condition 2.1.10(c)(i) and (iii) – The issued permit requires daily records based on CEMS data for emissions of PM, in addition to daily records for emissions of NOx, SO_2 and CO_2, as provided for by the draft permit. Daily records for CO emissions are only required if monitoring is conducted for CO. These changes correct oversights in the draft permit. Pursuant to Condition 2.1.9-3CEMS data for CO will only be required for the oxy-combustion boiler if the Permittee elects to comply with the alternative standard in the NSPS for combined NOx and CO, rather than the standard for CO (see). Pursuant to Condition 2.1.9-2, CEMS data will be required for PM, as well as for the other pollutants that were addressed in the draft condition.

Condition 2.1.10(c)(iii) – Records of monthly and annual emissions are also required for CO_2, as well as NOx, SO_2 and CO as provided by the draft permit. In addition, the issued permit requires records for CO only if monitoring is conducted. These changes make these recordkeeping requirements for the oxy-combustion boiler consistent with the continuous emissions monitoring that is conducted for this boiler.

Condition 2.1.10(c)(iv) – The issued permit now requires a file containing calculations including supporting documentation for the maximum hourly emission rates of $PM_{10}/PM_{2.5}$, sulfuric acid mist, fluorides, lead, VOM, methane, N_2O, individual HAP, total HAPs and, if monitoring is not conducted, CO. These records, which address pollutants for which continuous monitoring is not conducted, will provide reference information for the emissions of these pollutants from the oxy-combustion boiler relative to the hourly emission limits in Condition 2.1.6(b). These records will enhance the practical enforceability of those emission limits.

Condition 2.1.10(c)(v) – The issued permit requires records, including supporting calculations for monthly and annual emissions of PM_{10}/$PM_{2.5}$, sulfuric acid mist, fluorides, lead, individual HAP, total HAPs and, if monitoring is not conducted, CO, in addition to records for VOM and GHG, as provided for by the draft permit. These changes expand the scope of the required records to all pollutants emitted from the oxy-combustion boiler for which limits are set for which continuous emissions monitoring will not be conducted. The change will enhance the practical enforceability of the annual limits that are set for emissions of these pollutants.

Section 2.2: Unit-Specific Conditions for the Auxiliary Boiler

Condition 2.2.5(b)(ii) – In response to a comment, the issued permit requires the oil fired in the auxiliary boiler be ultra-low sulfur diesel oil thereby limiting the sulfur content of this oil to no more than 15 ppm sulfur, by weight. For this purpose, the fuel used in this boiler must comply with 40 CFR 80.520(a), without relying on the exception to 40 CFR 80.520(a) that is provided in 40 CFR 80.520(c). As a consequence, the auxiliary boiler is prohibited from firing any diesel oil that may currently be held at the Meredosia Energy Center that does not meet the specifications for ultra-low sulfur diesel fuel.

Condition 2.2.6 – In response to concerns expressed in comments that the project will be a major project for emissions of $PM_{2.5}$, with a significant net increase in emissions of $PM_{2.5}$, the permitted annual $PM_{2.5}$ emissions of the auxiliary boiler have been lowered in the issued permit. In the issued permit, annual emissions of $PM_{2.5}$ are limited to 4.9 tpy, rather than 16.6 tpy, as would have been provided by the draft permit. The hourly limits of for $PM_{2.5}$ emissions are also similarly lowered. The lower emission limits reflect emission data for $PM_{2.5}$ provided in the application. The draft permit would have set limits for emissions of $PM_{2.5}$ that were identical to the limits for PM_{10} as this would simplify the review of the determinations of compliance that are made by the source. In response to comments, separate, lower emission limits for $PM_{2.5}$ emissions were determined to be reasonable and appropriate to provide further assurance that the proposed project would not be significant for $PM_{2.5}$.

In addition, the issued permit limits sulfuric acid mist emissions from the auxiliary boiler to no more than 0.0124 tons per year. This new limit explicitly limits emissions of sulfuric acid mist from this boiler as they contribute to the increase in emissions from this proposed project that must be addressed in the netting analysis for sulfuric acid mist. The change is a consequence of comments concerning the emissions of sulfuric acid mist of the existing emergency generator at the Meredosia Energy Center, which was addressed as a contemporaneous emissions increase in the netting analysis for emissions of sulfuric acid mist.

Condition 2.2.7-2 (a)(ii) – To further verify compliance with applicable emission limits, emission testing requirements have been enhanced to now require testing from the auxiliary boiler for filterable PM, PM_{10} and $PM_{2.5}$ and condensable particulate matter, in addition to the testing for emissions of NOx and CO that would been provided for by the draft permit. However, if the Permittee considers all PM emissions to be emissions of filterable PM_{10} and $PM_{2.5}$, testing for emissions of filterable PM_{10} and $PM_{2.5}$ is not required unless such testing specifically requested by the Illinois EPA.

Condition 2.2.7(b) – Specific test methods and procedures are now have been added for the testing of the auxiliary boiler for emissions of filterable PM, PM_{10} and $PM_{2.5}$ and condensable particulate matter.

Conditions 2.2.8-1 and 2.2.9(a) – The compliance provisions for the fuel used in the auxiliary boiler, i.e., fuel sampling and recordkeeping, have been enhanced in the issued permit to address compliance with Condition 2.2.5(b), which requires use of ultra-low sulfur diesel with a sulfur content of no more than 15 ppm, by weight.

Condition 2.2.9(g) – In response to a comment, the issued permit further delineates the records that must be kept for the maximum hourly emission rates of the auxiliary boiler, specifying the pollutants for which such records are required (i.e., NOx, CO, PM, PM_{10}, $PM_{2.5}$, VOM, SO_2, sulfuric acid mist, GHG and total HAPs) and also requiring records for maximum emissions in lbs/mmBtu. These records will provide reference information for the emissions of these pollutants relative to the hourly emission limits in Condition 2.2.6 and facilitate the practical enforceability of those emission limits.

Section 2.3: Unit-Specific Conditions for New And Modified Coal-Handling

Condition 2.3.6 – In response to a comment concerning the need for additional limits for the emissions of particulate matter from the new and modified coal handling operation, additional emission limits have been set in the issued permit. In particular, emission limits for PM and $PM_{10}/PM_{2.5}$ in pounds per ton of coal and tons per year have been individually set for each operation, rather than limits on combined annual emissions, as would have been set by the draft permit. These additional limits reasonably enhance the practical enforceability of the emission limits for these operations. It will be simpler to review compliance of individual operations than to review compliance of the operations in aggregate. It also will be easier to review compliance with both short-term and annual emission limits than only an annual limit. However, it is not necessary to set separate limits for the $PM_{2.5}$ emissions of these operations. Limits for $PM_{10}/PM_{2.5}$ will simplify review of the determinations of compliance that are made by the source. Separate, lower emission limits for the $PM_{2.5}$ emissions are not needed to ensure that the net increase in emissions of $PM_{2.5}$ from the proposed project to be less than significant. Such limits also would not meaningfully affect the net change in emissions of $PM_{2.5}$ from this project.

Draft Condition 2.3.8(b) – This condition from the draft permit is not included in the issued permit. This condition, which would have required records for the relative share of the emissions of the different operations compared to the annual limit, is no longer needed. This is because Condition 2.4.6 in the issued permit sets emission limits for individual operations.

Condition 2.3.8(d) (i) – The recordkeeping provisions have been enhanced to appropriately address compliance with the new emission limits for PM and $PM_{10}/PM_{2.5}$ in Condition 2.3.6. Given that the issued permit sets separate emissions limits for each operation in pounds per ton of coal in addition to annual limits, it is appropriate to now require records that include records that address these limits, i.e., calculations, with supporting documentation, for the maximum emission rates of each operation in pounds per tons of coal handled.

Section 2.4: Unit-Specific Conditions for Bulk Handling Operations

Condition 2.4.5(b) – In response to a comment that the permit must include an enforceable requirement that dry ash be wetted to no less than15 percent moisture, the issued permit now sets a requirement for the moisture content of dry ash from the oxy-combustion boiler, including dry solids from the circulating dry scrubber, as loaded out from the facility. Consistent with the relevant information provided in the application, the moisture content of this material must be brought to at least 15 percent by weight in the pug mill that prepares this material for loadout.

Condition 2.4.6 – In response to a comment concerning the need for additional limits for the emissions of particulate matter from the lime system, trona system and ash system, additional emission limits have set in the issued permit. In particular, emission limits for PM and $PM_{10}/PM_{2.5}$ in pounds per ton of material handled and tons per year have been individually set for each operation, rather than limits on combined annual emissions, as would have been set by the draft permit. These additional limits reasonably enhance practical enforceability of the emission limits for these operations. However, it is not necessary to set separate limits for the $PM_{2.5}$ emissions of the subject operations. Limits for $PM_{10}/PM_{2.5}$ will simplify review of the determinations of compliance that are made by the source and separate, lower emission limits for the $PM_{2.5}$ emissions are not needed to ensure that the net increase in emissions of $PM_{2.5}$ from the proposed project is less than significant.

Condition 2.4.8-1 – In response to a comment requesting procedures to verify compliance with a requirement that dry ash from the oxy-combustion boiler be wetted to no less than 15 percent moisture, the issued permit requires operational monitoring for the amount of water mixed with the ash.

Draft Condition 2.4.9(a)(ii) – This condition from the draft permit is not included in the issued permit. This condition, which would have required records for the relative share of the emissions of the different operations compared to the annual limit, is no longer needed. This is because Condition 2.3.6 in the issued permit sets emission limits for individual operations.

Condition 2.4.9 – The recordkeeping provisions have been modified to appropriately document compliance with the new emission limits for PM and $PM_{10}/PM_{2.5}$ in Condition 2.4.6. Given that the issued permit sets separate emissions limits for each system in pounds per ton of material handled, in addition to annual limits, it is appropriate to now require records that address these limits, i.e., calculations, with supporting documentation, for the maximum emission rates of each system for PM and $PM_{10}/PM_{2.5}$ in pounds per tons of material handled. In addition, the Permittee is now required to maintain documentation of the design specifications for each filter for these operations and the manufacturer's recommended operating and maintenance procedures for these filters to verify compliance with the operating requirement of Condition 2.4.5(a), which requires the control devices on each operation be designed to emit no more than 0.02 gr/dscf.

Section 2.5: Unit-Specific Conditions for the Cooling Towers

Condition 2.5.6 – In response to a comment concerning the need for additional limits for the emissions of particulate matter from operations other than the cooling towers, additional emission limits have set in the issued permit for the cooling towers, including annual limits for each individual cooling tower. These additional limits reasonably enhance practical enforceability of the emission limits for the cooling towers.

Condition 2.5.7(a) – In response to a comment concerning the limits that would be set for the cooling towers, the issued permit requires sampling and analysis of the water being circulated in each cooling tower for total dissolved solids content to be conducted on at least a monthly basis, rather than a quarterly basis. This change reasonably enhances the practical enforceability of the emission limits that have been set for the cooling towers.

Section 2.6: Unit-Specific Conditions for Roadways

Condition 2.6.3(a) – In response to a comment that the issued permit should clearly state which haul roads are to be paved and further, that the issued permit should require the roads to be paved by the time the FutureGen project commences operation, the issued permit now requires the principal roadways at the facility to be paved. Paving is to be completed by the time of initial startup of the oxy-combustion boiler, provided, however, that the portions of principal roadways in areas where they might be damaged by the continuing presence of heavy construction equipment must be promptly paved after that equipment is removed and paving would no longer be at risk of being damaged; regardless, paving must be completed no later than 90 days after initial startup of the oxy-combustion boiler. In addition, the issued permit also requires that the paving be maintained in good condition.

Condition 2.6.3(d) – In response to a comment that fugitive emissions from the haul roads have been underestimated because the draft permit did not limit the maximum amount of coal that may be received by truck, the issued permit limits the amount of coal that is received by the facility by truck. For this purpose, the amount of coal received by truck is limited to 446,760 tons per year, consistent with information in the application for the maximum amount of coal that would be received by truck.

Condition 2.6.4 – In response to a comment concerning the need for a $PM_{2.5}$ emission limit from haul roads, the limit for PM_{10} emissions of haul roads is also applied to $PM_{2.5}$. A single limit for $PM_{10}/PM_{2.5}$ will simplify review of the determinations of compliance that are made by the source. Separate, lower emission limits for $PM_{2.5}$ emissions are not needed to ensure that the net increase in emissions of $PM_{2.5}$ from the proposed project is less than significant. A separate emission limit for $PM_{2.5}$ also would not meaningfully affect the net change in emissions of $PM_{2.5}$ from this project.

Condition 2.6.5-1(a)(ii) – The periodic inspections that are required to verify implementation of necessary control measures for roadways must now address whether the paving on the principal roadways is in good condition. This sets a compliance procedure for this requirement that applies to these roadways.

Condition 2.6.5-1(b)(vi) – The recordkeeping for required inspections must include the condition of the pavement on the principal roadways, to address whether paving is in good condition.

Condition 2.6.5-2 – In response to a comment that the silt loading assumed in the projection of particulate matter emissions from haul roads should be higher, consistent with the silt loading used in the permitting of certain projects in other states, a requirement for the Permittee to measure the average silt load at the facility has been included in the issued permit. Such testing and analysis shall be conducted employing "Procedures for Sampling Surface/Bulk Dust Loading," Appendix C.1 in Compilation of Air Pollutant Emission Factors, USEPA, AP-42. The required measurements will ensure that the particulate matter emissions of the haul roads at the facility are accurately determined and compliance with applicable emission limits is properly verified.

Condition 2.6.6(a)(ii) – In response to a comment, this condition has been revised to clarify and expand upon the records that are required. In the issued permit, the function of these projections of maximum particulate matter emissions for roadways, which are required by this condition, is more fully developed. These records must now also include a description of the control measures that are needed to ensure compliance with applicable emission limits considering the emissions that have been projected. These records must also include a determination whether compliance with applicable emissions limits that have been set for roadways necessitates implementation of control measures in accordance with a written operating program.

Condition 2.6.6(c) – In response to a comment, this condition requires specific recordkeeping for the amounts of different materials transported on haul roads. This information consists of records of the amount of coal (truck only), lime and trona received by the plant and the amount of ash loaded out from the plant in tons per month and tons per year. These records will address the limits that has been set for the amount of coal that is received by truck and generally provide operational data that is needed to determine the particulate matter emissions of roadways.

<u>Attachment 1: Summary of Project Emissions</u>

Table 1A: Summary of Project Emissions (Tons/Year) - Various changes have been made in this table consistent with the various changes discussed above, including: 1) Addition of data for emissions of sulfuric acid mist from certain units for which it was not previously provided; 2) Reductions in the emissions of certain pollutants from the oxy-combustion boiler as a consequence of limiting annual operation of this boiler in air-firing mode to 4,800 hours per year; and 3) A reduction in the $PM_{2.5}$ emissions of the auxiliary boiler as a consequence of setting separate limits for $PM_{2.5}$. The overall result is lower project emissions for CO, VOM, SO_2, PM, PM_{10}, $PM_{2.5}$ and fluorides and slightly higher project emissions for sulfuric acid mist.

Table 1B: Analysis of Net Changes in Emissions (Tons/Year) - Various changes have been made to this table as a consequence of the changes to Table 1A. In particular, for CO, SO_2, PM, PM_{10} and $PM_{2.5}$ (i.e., pollutants for which the permitted emissions of the project emissions are now lower, netting is being conducted and there is a net decrease in emission), the net decrease in emission considering contemporaneous increases and decreases in emissions is now even greater. For sulfuric acid mist, for which the net increase in emissions is less than significant and the permitted emissions of the project are slightly higher, the net increase in emissions is also slightly higher. This is due not only to the slightly higher emissions of sulfuric acid mist for the project but also consideration of a contemporaneous increase in emissions of sulfuric acid mist from the existing emergency engine generator at the Meredosia Energy Center.

<u>**Changes to the Permit for the Emergency Engine at the Sequestration Facility, Permit No. 12020051**</u>

Condition 6(a)(ii) – The issued permit limits the emissions of sulfuric acid mist from the emergency engine generator to no more than 0.0088 tons per year. This new limit explicitly limits emissions of sulfuric acid mist from this engine as they contribute to the increase in emissions of sulfuric acid mist from this proposed project that must be addressed in the netting analysis for sulfuric acid mist. The change is a consequence of comments concerning the emissions of sulfuric acid mist of the existing emergency generator at the Meredosia Energy Center that was addressed as a contemporaneous emissions increase in the netting analysis for this project for emissions of sulfuric acid mist.

Condition 8(b) –This condition requires additional recordkeeping to verify compliance with the limit in Condition 6(a)(ii) for the emissions of sulfuric acid mist from the emergency engine generator. The additional records include records for the methodology by which the source determines the emissions of sulfuric acid mist from the engine, relevant records for the operation of this engine, and records for the actual emissions of sulfuric acid mist from the engine.